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SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS. PHILLIPS POWER STATION, DUQUESNE LIGHT COMPANY

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16. ABSTRACT: The report gives results of a survey of the flue gas desulfurization system at Duquesne Light Co.'s 400 MW Phillips Power Station, where four parallel Chemico venturi scrubber trains are installed. In addition to the first stage particulate scrubbers, one of the four trains includes a second stage venturi absorber for the control of SO2 emissions. The system uses slaked lime as the absorbing medium and has been operational since July 1973. An overall SO2 removal efficiency of 50 to 60 percent has been attained. The use of magnesium oxide-modified lime is being investigated in an effort to increase the SO2 removal efficiency of the existing system. Numerous start-up and operational problems have been encountered and corrected. A 10-month evaluation of the system was initiated in December 1974 to determine whether additional SO2 removal equipment will be installed.

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Flue Gases	Coal	Stationary Sources	21B 21D
Desulfurization	Combustion	Venturi Absorbers	07A, 07D
Scrubbers	Cost Engineering	Particulate	14A
Sulfur Dioxide		Slaked Lime	07B
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SIGNIFICANT DATES

December, 1969	-	Gibbs & Hill, Inc. requested to study methods of compliance.
September, 1970	-	Gibbs & Hill study recommends scrubber and Duquesne Light Company gave authority to Gibbs & Hill to proceed with projects at Elrama and Phillips Power Station.
October, 1970	-	Invitations were extended to bid on scrubber pilot plant.
February-May, 1971	-	Chemico pilot scrubber tests at Phillips underway.
May, 1971	-	Design of full scale system started.
July, 1971	-	Contract for scrubber process including scrubber recycle pumps, reheater and associated controls and instrumentation awarded to Chemico.
December, 1971	-	Construction started at both Phillips and Elrama plant sites.
July, 1973	-	Construction of Phase I at Phillips essentially complete. Phase I consists of one dual stage SO_2 scrubber train and 3 single stage particulate scrubber train with associated lime and thickener equipment.
July 9, 1973	-	Operation began at Phillips with two and eventually three of station's six boilers.
October 8, 1973	-	Scrubber system shutdown for extensive repair.
March 17, 1974	-	Scrubber system began with three of six boilers.
August 26, 1974	-	Fourth boiler cut into scrubber system.
October, 1974	-	Fifth boiler cut into scrubber system.

Figure 5

EPA-650/2-75-057-c

SURVEY OF FLUE GAS DESULFURIZATION SYSTEMS

PHILLIPS POWER STATION, DUQUESNE LIGHT CO.

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The author appreciates the efforts and cooperation of everyone who participated in the preparation of this report.

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SUMMARY

Four parallel Chemico venturi scrubber trains have been installed at the 400 MW Phillips Power Station of Duquesne Light Company.

Each of the four trains has a first stage venturi for SO_2 and particulate removal; one of the four trains includes a second stage venturi absorber for the additional control of SO_2 emissions. The system uses slaked lime as the absorbing medium and has been operational since July 1973. An overall SO_2 removal efficiency for the plant of 50-60 percent has been attained. The two stage train has achieved approximately 90 percent SO_2 removal efficiency. The use of magnesium oxide-modified lime is being investigated in an effort to increase the SO_2 removal efficiency of the existing system.

Numerous start-up and operational problems have been encountered and corrected. A ten-month evaluation of the system was initiated in December 1974 to determine whether additional SO_2 removal equipment will be installed.

Pertinent data on the facility and FGD system operation are summarized in the following table.

SUMMARY OF FGD DATA - PHILLIPS

Station Rating	373 MW (net) after scrubber derating
Fuel Characteristics	Coal: 11,350 BTU/lb, 18.2% ash, 2.15% sulfur
Prime A/E	Gibbs and Hill, Inc.
FGD Vendor	Chemico
Process	Wet lime
New or Retrofit	Retrofit
Start-up Date	August 1973 (SO_2 absorber)
FGD Modules	Four first stage; one second stage
Efficiency, overall	
Particulate	99 percent
SO_2	50-60 percent
Water Make-up	1.7 gpm/MW (net)
Sludge Disposal	Stabilization and haul to landfill
Unit Cost	$38 million ($102/net KW) capital[a]
	$15 million/yr (5.9 mills/net KWH) operating including indirect charges on capital

[a] An estimated $15 million that may be required for sludge disposal facilities are not included in this cost.

1.0 INTRODUCTION

The Control Systems Laboratory of the U.S. Environmental Protection Agency has initiated a study to evaluate the performance characteristics and degree of reliability of flue gas desulfurization (FGD) systems on coal-fired utility boilers in the United States. This report on the Phillips Power Station of Duquesne Light Company is one of a series of reports on such systems. It presents values of key process design and operating parameters, describes the major start-up and operational problems encountered at the facility and the measures taken to alleviate such problems, and identifies the total installed and annualized operating costs.

This report is based upon information obtained during a plant inspection on August 22, 1974, and on subsequent data provided by Duquesne Light Company and Chemico personnel.

Section 2.0 presents pertinent data on facility design and operation including actual and allowable particulate and SO_2 emission rates. Section 3.0 describes the flue gas desulfurization system and Section 4.0 analyzes FGD system performance.

2.0 FACILITY DESCRIPTION

2.1 PLANT LOCATION

The Phillips Power Station of the Duquesne Light Company is located on the Ohio River in Allegheny County, Pennsylvania, 20 miles northwest of Pittsburgh, Pennsylvania. The area is heavily industrialized, and the plant supplies electricity to residential, commercial, and industrial users in Allegheny and Beaver Counties.

2.2 BOILER DATA

Six generating units at the station constitute a total nominal generating capacity of 400 MW. The net station capacity will be 373 MW with four scrubber modules and four absorber modules installed. At the present time only one absorber module has been installed. All the generators are cycling base load units. Unit No. 6 is the largest generator, having a net capacity of 143 MW. All the boilers were manufactured by Foster-Wheeler and are dry-bottom, pulverized-coal-fired units. The first unit was installed in 1942, and the sixth one in 1956. Coal at this station has an average, as received, gross heating value of 11,350 BTU/lb. Ash content, on a dry basis, is 18.2 percent, and sulfur content is 2.15 percent.

2.3 POLLUTION CONTROLS

Primary particulate emission control at this plant is provided by Research-Cottrell mechanical collectors followed by a Research-Cottrell electrostatic precipitator (ESP) on each boiler. The collection efficiency for this system was originally estimated to be 90 percent. However, disruption of the gas flow distribution through the ESP resulted from the design of the ducts which tie in to the FGD system so that apparently the combined efficiency through the mechanical and electrostatic system is only about 80 percent.

Final particulate control is achieved by four parallel Chemico venturi scrubbers with a design efficiency of 99 percent. Outlet grain loadings from the scrubbers have been measured to be less than 0.04 grains per standard cubic foot. These scrubbers also remove about 50 percent of the SO_2 entering them when lime is added (for pH control).

SO_2 emissions from one scrubber are further controlled by a Chemico second-stage venturi absorber recirculating a lime solution. SO_2 removal efficiency for this two-stage train has averaged about 90 percent based on performance guarantee tests. Overall SO_2 removal efficiency is therefore about 50-60 percent when pH can be maintained between 6-7.

At the present time the FGD absorber facilities consist of a two stage absorber module processing about 125 MW equivalent of flue gas and three single stage absorber modules

processing gas from the balance of the station's nominal 400 MW capacity. Present plans provide for the installation of up to three more FGD absorbers if they are found to be necessary.

The scrubber and absorber facilities derate the station capacity by 14 MW. This effects an increase in station heat rate from a previous level of 11,500 BTU/KWH (net) to about 11,900 BTU/KWH (net).

Table 2.1 presents pertinent data on plant design, operation, and atmospheric emissions.

Table 2.1 DATA ON PLANT DESIGN,

OPERATION AND EMISSIONS

DUQUESNE LIGHT COMPANY - PHILLIPS POWER PLANT

Station Data	Item
Maximum theoretical continuous generating capacity, MW (net) with 4 scrubbers and 1 absorber operating	373
Average capacity factor (1974), %	70
Boiler manufacturer	Foster-Wheeler
Year placed in service	1942-1957
Station heat rate, BTU/KWH (net)	11,900
Maximum heat input MM BTU/hr	4463
Stack height above grade, ft	340
Maximum flue gas rate, acfm @ 360°F	1,850,000
Emissions Controls:	
Particulates	Multicyclones ESP Venturi Scrubber
SO_2	Venturi Absorber
Particulate Emission Rate:	
Allowable, lb/MM BTU	0.08
Actual, lb/MM BTU	0.08 est
SO_2 Emissions Rate:	
Allowable, lb/MM BTU	0.6
Actual, lb/MM BTU	1.9 est

3.0 FLUE GAS DESULFURIZATION SYSTEM

3.1 PROCESS DESCRIPTION[a]

Lime to be introduced to the FGD system at Phillips is initially activated by slaking it to form calcium hydroxide. This slaked lime, along with the recirculation calcium sulfite-rich slurry constitute the scrubbing liquor. Reaction with SO_2 in the flue gas takes place in the liquid phase. Following are the principal chemical reactions in the lime-base flue gas desulfurization processes:

Lime slaking: $CaO + H_2O \longrightarrow Ca(OH)_2$ (1)

Sulfite formation: $Ca(OH)_2 + SO_2 \longrightarrow CaSO_3 + H_2O$ (2)

Bisulfite formation: $CaSO_3 + SO_2 + H_2O \rightarrow Ca(HSO_3)_2$ (3)

Sulfate formation: $2CaSO_3 + O_2 \longrightarrow 2CaSO_4$ (4)

Formation of sulfate (reaction 4) in the absorber module is undesirable and should be suppressed.

The Phillips FGD system may ultimately consists of four identical parallel trains, each train consisting of a particulate scrubber module and a SO_2 absorber module in series. At the present time, all six boilers have been tied in to the

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[a] Adapted from "Duquesne Light Company, Phillips Power Station Lime Scrubbing Facility," Steve L. Pernick, Jr. and R. Gordon Knight, Presented at EPA FGD Symposium, Atlanta, November 4-7, 1974, and supplemented with information obtained during plant visit. See Appendices A and C.

scrubbing system; only one of the four scrubbers has a second-stage absorber installed in conjunction with it for the removal of SO_2. The exhaust streams of all six boilers at the station are manifolded together so that the components of the emission control system are not directly associated with specific boilers. This system allows maximum flexibility for emission control when various components of the FGD system must be shut down for maintenance or repair. There is also provision to bypass the whole FGD system under emergency conditions. However, in order to accomplish the bypass it is necessary to shut down the boilers and to remove blank-off plates from the exhaust gas stream. Sixteen-foot diameter ducts lead to each of the four first-stage scrubbers.

Figure 3.1 is a schematic flow diagram for this installation. Hot flue gas (about 500,000 acfm at 340°F) containing fly ash and sulfur dioxide (about 1400 ppm SO_2) enters the first-stage scrubber and impinges upon the upper cone. One-half (8250 gpm) of the total scrubber recycle liquor for each module is introduced into the vessel through the bull nozzle where it is sprayed over the surface of the upper cone, to initiate the scrubber action. The rest of the scrubber recycle liquor enters through tangential nozzles above the adjustable throat damper. The flue gas and scrubbing liquor are vigorously contacted in the throat section of the scrubber where the particulates and some SO_2 are removed.

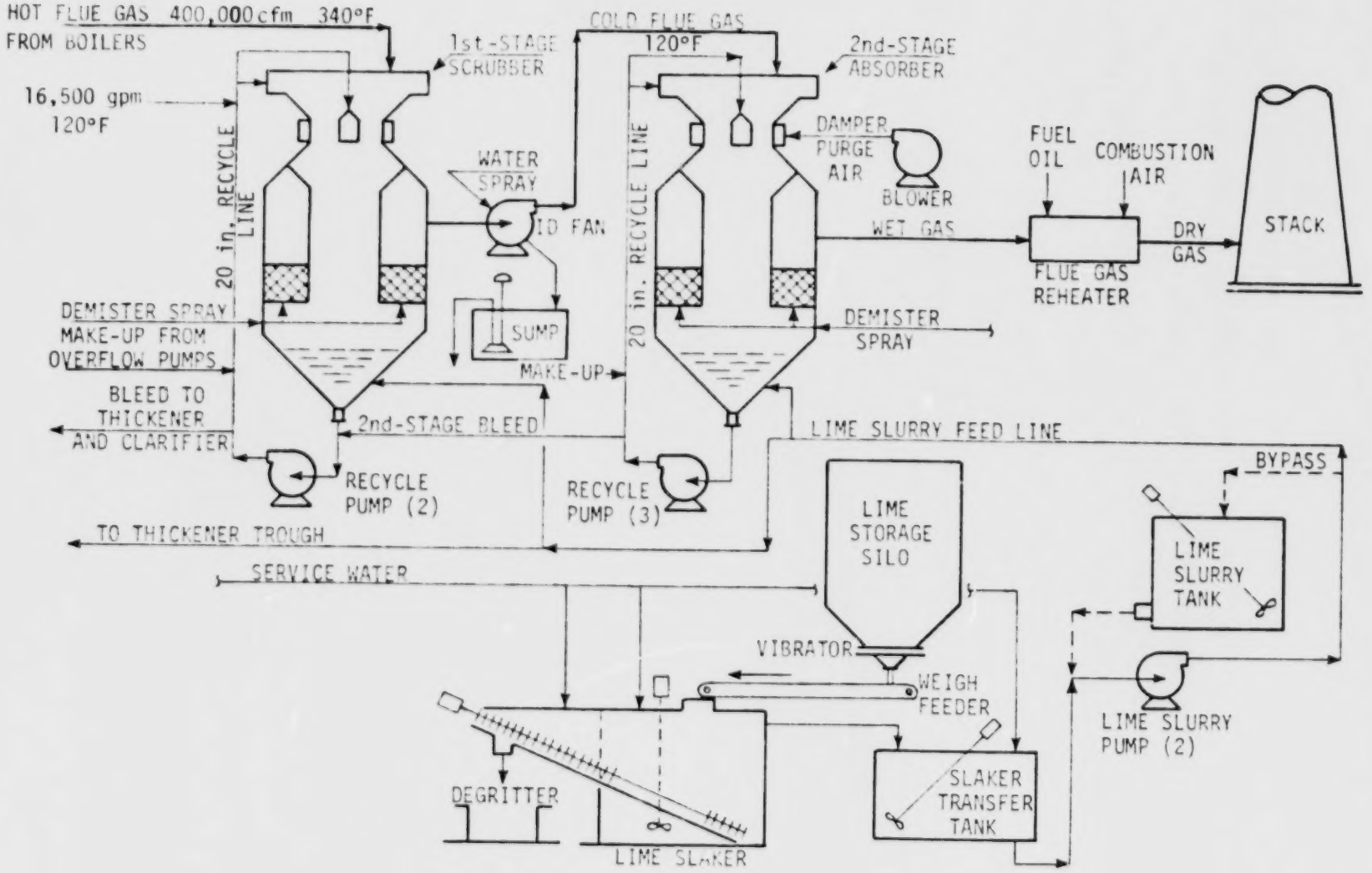

Figure 3.1. General flow diagram of the FGD system at the Phillips Power Station.

The gas and liquor continue downward to the separator section where, after being separated from the scrubbing liquor, the flue gas enters a spray-washed demister where entrained liquor is removed. The gas leaves the scrubber and enters a booster ID fan which is equipped with fresh water sprays to remove any accumulation of solids resulting from scrubber carryover.

The ID fan housings are lined with 1/4-inch thick natural rubber. Wheel material is Carpenter 20 Cb 3, a stainless steel containing niobium and tantalum. The fan shaft is 316L stainless steel. Each fan is driven by a 5500 horsepower, 1200 rpm, 4160 volt electric motor. A closed system supplies cooling water to the fan bearings.

Outlet gas temperature from the first stage scrubber is monitored and is normally in the 110-120°F range. At 175°F a control valve automatically opens to admit emergency cooling water to the upper cone. Additional temperature rise automatically shuts down the fan and closes the isolation dampers.

The gas leaving the ID fan enters one of two vessels depending on the train. In the case of the three single-stage scrubber trains, the gas enters an entrainment separator in which entrained scrubbing liquor that has been diluted by the fan sprays is separated and collected. These separators will be replaced by second-stage absorber vessels where the test program indicates that additional absorbers are feasible. In the case of the SO_2 prototype train, gas

leaving the ID fan enters a second stage absorber vessel, which is identical in size and design to the first stage scrubber. This second vessel is equipped with lime slurry injection nozzles.

Lime is fed from a storage silo at a controlled rate to a lime slaker where it is mixed with fresh make-up water. The slaked lime overflows to a slaker transfer tank where make-up water is added to provide a constant flow of lime slurry with a 15-percent solids concentration. Lime composition is 95 percent pure CaO, balance inert. Design lime requirement is 130 percent of the stoichiometric requirement. At a station heat rate of 11,900 BTU/KWH, a coal gross heat content of 11,350 BTU/lb and a sulfur content of 2.1 percent, design lime consumption for the single train is calculated to be about 4650 lb/hr.

The scrubbing liquor is circulated by two recycle pumps (Carpenter 20 Cb 3). Some of the recycle liquor is bled to the first-stage scrubber and part of the first-stage recycle stream is bled to the thickeners.

Total recycle flow is about 16,500 gpm per stage with a 615 gpm bleed to the thickeners. All single-stage vessels have been fitted with reagent nozzles so that pH control can be maintained and so that an approximate SO_2 removal efficiency of 50 percent can be accomplished.

The exit gases leaving either the second stage absorber or the entrainment separator enter a common wet duct lined with Flakeline 103 (a product of the Ceilcote Company consisting

of a glass-flake-filled modified polyester resin, subsequently referred to as Ceilcote) which leads to a new 340 ft, acid-resistant, brick-lined, concrete stack. A 316L stainless steel section of the duct, preceding the stack is equipped with a direct oil-fired reheater unit that can raise stack gas temperatures as much as 30°F. Normal reheat is about 20°F.

Bleed streams from the absorber and the scrubbers enter a trough which feeds two 75-foot diameter thickeners. The overflow from these thickeners runs to an overflow tank where it is pumped by two, 2000 gpm 316L stainless steel pumps to the make-up line for return to the scrubber system.

Underflow from each thickener, 105 gpm, at 40 to 45 percent solids concentration, is pumped by a 15 horsepower pump to one of three clay-lined sludge holding ponds. Each pond has a capacity of about 6500 cubic yards. Just prior to discharge to the holding ponds, the sludge enters a mixing tank where a stabilizing agent is added at a predetermined rate based on the density of the sludge as it leaves the thickener.

Settling and curing take place in the pond. Supernatant liquid reenters the scrubber system via the thickeners. Overflow from the thickeners is pumped back to the make-up line for return to the scrubber system. The sludge curing ponds provide interim storage while stabilization is taking place. One pond receives thickener underflow while a second is curing and the third is being excavated for final off-site disposal.

A service (river) water system independent from the power station service water system is provided. It includes a pair of 900 gpm, 100 horsepower pumps taking suction from the existing condenser discharge tunnel and a 10-inch distribution header for the scrubber facility. It provides fan spray water, pump seal water, demister spray water, instrumentation flush water, reagent mixing tank water, and emergency water for the scrubbers.

With present loads on the FGD system an excess of water is entering the system so that closed-loop operation is not possible. Excess water is discharged to the bottom ash settling ponds and from these into the river. An early attempt to operate in closed-loop mode resulted in a buildup in chloride concentration to 4000 ppm, causing significant corrosion damage to Carpenter 20 steel fan parts, scrubber internals, and dampers. Operating parameters are summarized in Tables 3.1 and 3.2.

3.2 INSTALLATION SCHEDULE

In December 1969 Gibbs and Hill, Inc. was retained to conduct a comprehensive study of the most feasible means of complying with current and anticipated emission regulations applicable to the Phillips and Elrama Power Stations of Duquesne Light Company. In September 1970 Gibbs and Hill submitted the results of that study indicating that stack gas desulfurization was the most practical means of achieving compliance at both stations. The consultant also concluded that a dual-stage venturi scrubbing system should be pilot

Table 3.1 SUMMARY OF SCRUBBER DATA

PHILLIPS POWER STATION

	Particulate Scrubber Modules	FGD Scrubber Modules
Superficial gas velocity, ft/sec	40	40
Module size	40'diam x 50'h	45'diam x 50'h
Equipment internals	Venturi	Venturi
Material of Construction		
Shell	Mild steel, Ceilcoted	Mild steel, Ceilcoted
Internals	Some 316L stainless, Ceilcoted	Some 316L stainless, Ceilcoted

Table 3.2 SUMMARY OF TANK DATA

PHILLIPS POWER STATION

Item	Scrubber Recirculating Tank	Thickener
No. of units	1	2
Unit size	20'diam x 30'h	70' diam x 40'
Retention time at full load	1.2 minutes	
Temperature °f	120°F	ambient
pH	5	4-6
Solids Conc. %		40-45 (Underflow)
Materials of Construction	mild steel	mild steel, Celicoted

tested. Pilot scrubber specifications were prepared and issued to five vendors in September 1970. The successful vendor, Chemico, Inc., installed a 1500 cfm pilot unit in February 1971 and completed tests in May of that year. In July 1971 Chemico was awarded a contract to build a full scale system consisting of four particulate scrubbers and a second-stage SO_2 absorber connected to one of the four scrubbers along with lime injection, recycle pump and reheater equipment. Gibbs and Hill, Inc. the Architect/Engineer firm for the project was responsible for the remaining design of the system. This construction was completed in July 1973 to a point where start-up was possible. The single SO_2 absorber is to serve as a basis for decisions concerning the installation of additional SO_2 facilities at the Phillips and Elrama Stations. Five particulate scrubbers have been installed at the Elrama Station.

3.3 COST DATA

As of April 1, 1975, the system at Phillips represents a capital investment of approximately $33 million. It is expected that an additional $7 million may be required for additional equipment necessary to comply with the SO_2 emission limitations. This cost includes all process equipment, engineering costs, contractors' fees, and interest on capital during construction. This will represent a total investment of $40 million or approximately $103 per net kilowatt, exclusive of the costs of additional sludge disposal facilities that may be required.

A recent estimate indicates that the annual operating and maintenance expenses at Phillips, excluding additional sludge disposal requirements, but including fixed charges estimated at 14.5 percent of capital costs, with full SO_2 scrubbing will be about $15 million per year, or 5.9 mills per kilowatt hour.

In an effort to estimate the total capital and operating costs that would utimately be incurred for the scrubber system at the Phillips Station, including provision of adequate sludge disposal facilities for full SO_2 removal, a preliminary evaluation was made of the additional property required for development into a disposal area and the additional expenses involved in disposing of the sludge. This estimate indicates total capital expenditures approximately $147 per KW.

Present estimates of sludge disposal costs are $5 to $7 per wet ton of sludge (40 percent solids).

4.0 FGD SYSTEM PERFORMANCE ANALYSIS

4.1 START-UP PROBLEMS AND SOLUTIONS

The initial schedule for this installation called for start-up of the FGD system on January 1, 1973, to be followed by a two-month shakedown period and a ten-month test period to evaluate the feasibility of the system, so that by January 1974 decisions could be made regarding additional equipment installations at the Phillips and Elrama Power Station.

Actual start-up lagged the target date by about six months, and the ten-month test program initiation was delayed nearly two years. A detailed description of the causes for these delays has been published and is included in this report as Appendix C. Problems and solutions are outlined briefly in the following paragraphs.

The six month start-up delay was attributed to several factors. Some engineering delays occurred as a result of efforts to incorporate ongoing experience gained at other Chemico FGD installations. Equipment delivery delays and fabrication errors also occurred. Some defective equipment, such as fans, had to be field repaired. Failures of electrical switchgear and transformers occurred during field tests preliminary to start-up.

The scrubber system was put in operation on July 9, 1973, although the lime additive system was not ready at that time. Operation without lime resulted in excessive scrubber liquid acidity that quickly corroded some components of the FGD system, including pumps and piping. The system operated for two weeks before it was shut down for a two-week repair period due to a leak in the stack seal. On August 5, 1973, the system was restarted with the lime feed system operational, and ran until October 8, 1973 when it was shut down until March 17, 1974.

Scale deposits developed in the scrubbers, and the scale had to be removed periodically. Corroded fan dampers and scrubber cones were Ceilcoted. Exhaust gas expansion joints were replaced, fan welds were reground, and stack mortar joints were repaired. Many parts were found to be constructed of off-spec 304 stainless and had to be replaced with originally specified 316L material.

An early attempt to operate the system in a closed-loop mode resulted in a buildup of chloride ion concentration in the scrubber recirculating system to about 4000 ppm, intensifying the existing corrosion problems and causing additional ones.

Installation of the ductwork to the FGD system caused a flow disruption through the existing ESP so that the particulate efficiency of the unit was reduced considerably. This resulted in excessive fly ash carryover into the scrubber and the consequent generation of excessive quantities of

sludge. Additional sludge was also created by treating the single stage scrubber trains with lime. As a result the spare thickener capacity had to be utilized constantly, and the sludge holding pond capacity was reduced to about a 10-day fill period as compared to a 28 day design period. This situation plus the high outage rate for the stabilizing agent injection equipment often made it necessary to transport sludge by truck to the disposal area in a fluid state.

4.2 PERFORMANCE TEST RUN

A ten-month test program was initiated in December, 1974. At that time five of the six boilers at the Phillips Plant were connected to the scrubber system. This program will evaluate the efficiency, reliability, and practicability of the system. A decision should then be made late in 1975, concerning the installation of additional SO_2 removal equipment for compliance with the SO_2 emission limitations. The number of additional second stage absorbers required for compliance with the regulations will be determined during the ten-month test program, and this will establish the completion date for installation of all additional FGD equipment.

In the hope of obtaining higher efficiencies of SO_2 removal with the use of lime, Duquesne Light is conducting tests using a lime containing 4 to 6 percent magnesium oxide. Various tests on pilot systems indicate that the higher reactivity of such a lime results in SO_2 single-stage removal efficiencies above 80 percent. In preparation for

these tests, one of the single-stage scrubbers was isolated along with one of the thickener tanks. This isolation was necessary to establish and maintain the necessary conditions in the test scrubber and one thickener. A test run with the high MgO was made in September, 1974. However, it has been difficult to achieve a sufficiently high rate of utilization of the magnesium oxide. A few cursory tests under these conditions indicate SO_2 removal efficiencies somewhat better than those with high calcium lime, but also significantly less than anticipated. The tests were suspended in September to further evaluate means of increasing the reactivity and utilization of the magnesium lime. Additional tests with lime in early November showed that better pH control could be obtained if the lime slurry was heated. It is believed that this reagent holds promise, but the tests were not conclusive because of inconsistencies in the quality of the lime supplies and the difficulty in blending and obtaining sufficient supplies.

4.3 PERFORMANCE PARAMETERS

The ultimate SO_2 removal efficiency needed to comply with emission regulations is about 83 percent. However, the present equipment installed using only one two-stage system and three single-stage scrubber trains with lime is producing an estimated SO_2 removal efficiency of 50-60 percent. Availability, was reported to be 100 percent in January 1975, but this figure is misleading since there is considerable scrubber redundancy in the system at the present

time. (Percent availability is defined as 100 times the ratio of system operating hours to boiler operating hours).

4.4 PROCESS MODIFICATIONS FOR FUTURE INSTALLATIONS

The design of additional installations will rely heavily on operating experience gained from this system. The discussion in Section 4.1 points out many areas where system improvements can be made, especially regarding material selection, quality control, and equipment sizing. Ongoing operational experience during the ten-month test program will help to optimize process design parameters for future control systems, if such systems are indicated.

APPENDIX A

PLANT SURVEY FORM

PLANT SURVEY FORM

NON-REGENERABLE FGD PROCESSES

A. COMPANY AND PLANT INFORMATION

1. COMPANY NAME: Duquesne Light Co.
2. MAIN OFFICE: 435 Sixth Avenue, Pittsburgh, Pa.
3. PLANT MANAGER: I.S. Abbott
4. PLANT NAME: Phillips Power Station
5. PLANT LOCATION: Cresant Township, Allegheny County, Pa.
6. PERSON TO CONTACT FOR FURTHER INFORMATION: S.L. Pernick, Jr.
7. POSITION: Manager Environ. Affairs
8. TELEPHONE NUMBER: (412) 471-4300
9. DATE INFORMATION GATHERED:
10. PARTICIPANTS IN MEETING

	AFFILIATION
Wade H. Ponder	EPA
John Busik	EPA
Tim W. Devitt	PEDCo
Fouad K. Zada	PEDCo
Robert D. O'Hara	D. L. Co.
I. S. Abbott	D. L. Co.
R. G. Knight	D. L. Co.

B. PLANT DATA. (APPLIES TO ALL BOILERS AT THE PLANT).

	BOILER NO.					
	1	2	3	4	5	6
CAPACITY, MW (Gross)	35	35	65	65	65	148
SERVICE (BASE, PEAK)	P-B	P-B	P-B	P-B	P-B	P-b
FGD SYSTEM USED	Wet Gas Venturi Scrubber					

C. BOILER DATA. COMPLETE SECTIONS (C) THROUGH (R) FOR EACH BOILER HAVING AN FGD SYSTEM.

1. BOILER IDENTIFICATION NO. 1-6
2. MAXIMUM CONTINUOUS HEAT INPUT 4463 MM BTU/HR
3. MAXIMUM CONTINUOUS GENERATING CAPACITY 387 MW (net)
4. MAXIMUM CONTINUOUS FLUE GAS RATE, 2,300,000 ACFM @ 380 °F
5. BOILER MANUFACTURER Foster-Wheeler
6. YEAR BOILER PLACED IN SERVICE 1942-1956
7. BOILER SERVICE (BASE LOAD, PEAK, ETC.)
8. STACK HEIGHT 340' Scrubber Stack
9. BOILER OPERATION HOURS/YEAR (197)
10. STATION CAPACITY FACTOR* 70%
11. RATIO OF FLY ASH/BOTTOM ASH 85

* DEFINED AS: $\frac{\text{KwH GENERATED IN YEAR}}{\text{MAX. CONT. GENERATED CAPACITY IN KW x 8760 HR/YR}}$

D. FUEL DATA

1. COAL ANALYSIS (as received)

	MAX.	MIN.	AVG.
GHV (BTU/LB.)	12600	10700	11350
S %	2.8	1.0	2.15
ASH %	23	9.5	18.2

2. FUEL OIL ANALYSIS (exclude start-up fuel)

GRADE	N/A	
S %		
ASH %		

E. ATMOSPHERIC EMISSIONS

1. APPLICABLE EMISSION REGULATIONS

	PARTICULATES	SO_2
a) CURRENT REQUIREMENTS	0.08 lb/10^6 BTU	0.6 lb/10^6 BTU
AQCR PRIORITY CLASSIFICATION	I	I
REGULATION & SECTION NO.	Article 18 Allegheny County Health Department	
MAX. ALLOWABLE EMISSIONS LBS/MM BTU	Same as above	
b) FUTURE REQUIREMENTS, COMPLIANCE DATE	Same as above	
REGULATION & SECTION NO.	Same as above	
MAXIMUM ALLOWABLE EMISSIONS LBS/MM BTU	Same as above	

2. PLANT PROGRAM FOR PARTICULATES COMPLIANCE

Connect all six boilers to common header to four particulate scrubbers

3. PLANT PROGRAM FOR SO_2 COMPLIANCE Operate 10 months for SO_2 prototype module including single stage scrubbers with lime. Based on outcome of tests determine how many additional second stage scrubbers required to come into compliance. Roughly assume 28 months for second scrubber, 19 months for third scrubber, 18 months for fourth scrubber.

F. PARTICULATE REMOVAL

1. TYPE	MECH.	E.S.P.	FGD
MANUFACTURER	R-C	R-C	Chemico
EFFICIENCY: DESIGN/ACTUAL			99/N.A.
MAX. EMISSION RATE* LB/HR			
GR/SCF			
LB/MMBTU			0.08

DESIGN BASIS, SULFUR CONTENT 2.3%

G. DESULFURIZATION SYSTEM DATA

1. PROCESS NAME: Lime scrubbing
2. LICENSOR/DESIGNER NAME: Chemico Co.
   ADDRESS: 1 Penn Plaza NY, NY 10001
   PERSON TO CONTACT: Paul Chopra
   TELEPHONE NO.: (212) 239-5100
3. ARCHITECTURAL/ENGINEERS, NAME: Gibbs and Hill, Inc.
   ADDRESS: 393 Seventh Avenue NY, NY 10001
   PERSON TO CONTACT: Mr. Joseph V. Armao
   TELEPHONE NO.:
4. PROJECT CONSTRUCTION SCHEDULE:

	DATE	
a) DATE OF PREPARATION OF BIDS SPECS.	Pilot scrubber, 9/70	
b) DATE OF REQUEST FOR BIDS	10/70 pilot, 3/71 full scale	
c) DATE OF CONTRACT AWARD	12/70 G&H 7/71 Chemico	
d) DATE ON SITE CONSTRUCTION BEGAN	7/71	Phase I
e) DATE ON SITE CONSTRUCTION COMPLETED	7/73	Phase I
f) DATE OF INITIAL STARTUP	July 1973	
g) DATE OF COMPLETION OF SHAKEDOWN	In Progress	

*At Max. Continuous Capacity

5/17/74

5. LIST MAJOR DELAYS IN CONSTRUCTION SCHEDULE AND CAUSES:

Equipment delivery, Electrical, Duct Work, Fans

I.D. Fan defects in welds

Lack of space to install equipment restricted workers

Boiler house ductwork erection, method of handling at site difficult

Selection and development of sludge disposal techniques.

6. NUMBER OF SO_2 SCRUBBER TRAINS USED 1

7. DESIGN THROUGHPUT PER TRAIN, ACFM @ 340 °F 547,000

8. DRAWINGS: 1) PROCESS FLOW DIAGRAM AND MATERIAL BALANCE
See G & Hill or Chemico
2) EQUIPMENT LAYOUT

H. SO_2 SCRUBBING AGENT

1. TYPE Lime

2. SOURCES OF SUPPLY See Dravo Corp. Mr. Wm. Lord Neville Island Pitts, Pa.

3. CHEMICAL COMPOSITION (for each source)

SILICATES

SILICA

CALCIUM OXIDE

MAGNESIUM OXIDE

4. EXCESS SCRUBBING AGENT USED ABOVE STOICHIOMETRIC REQUIREMENTS 30%

5. MAKE-UP WATER POINT OF ADDITION Scrubber Recycle

6. MAKE-UP ALKALI POINT OF ADDITION Scrubber Vessel Basins

J. SCRUBBER TRAIN SPECIFICATIONS:

1. SCRUBBER NO. 1 (a)

TYPE (TOWER/VENTURI) Venturi

LIQUID/GAS RATIO, G/MCF @ 120 °F

GAS VELOCITY THROUGH SCRUBBER, FT/SEC

MATERIAL OF CONSTRUCTION Carbon Steel

TYPE OF LINING Ceilcote

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.) Variable Throat Venturi

NUMBER OF STAGES 1

TYPE AND SIZE OF PACKING MATERIAL

PACKING THICKNESS PER STAGE (b)

MATERIAL OF CONSTRUCTION, PACKING:

SUPPORTS:

2. SCRUBBER NO. 2 (a)

TYPE (TOWER/VENTURI) Same as 1

LIQUID/GAS RATIO, G/MCF @ °F

GAS VELOCITY THROUGH SCRUBBER, FT/SEC

MATERIAL OF CONSTRUCTION:

TYPE OF LINING

INTERNALS:

TYPE (FLOATING BED, MARBLE BED, ETC.)

NUMBER OF STAGES

TYPE AND SIZE OF PACKING MATERIAL

a) Scrubber No. 1 is the scrubber that the flue gases first enter. Scrubber 2 (if applicable) follows Scrubber No. 1.

b) For floating bed, packing thickness at rest.

PACKING THICKNESS PER STAGE[b]

MATERIAL OF CONSTRUCTION, PACKING:

SUPPORTS:

3. CLEAR WATER TRAY (AT TOP OF SCRUBBER)

TYPE N/A

L/G RATIO

SOURCE OF WATER

4. DEMISTER

TYPE (CHEVRON, ETC.) Chevron

NUMBER OF PASSES (STAGES)

SPACE BETWEEN VANES

ANGLE OF VANES

TOTAL DEPTH OF DEMISTER

DIAMETER OF DEMISTER

DISTANCE BETWEEN TOP OF PACKING AND BOTTOM OF DEMISTER

POSITION (HORIZONTAL, VERTICAL)

MATERIAL OF CONSTRUCTION

METHOD OF CLEANING Internal Auto Sprays

SOURCE OF WATER AND PRESSURE

FLOW RATE DURING CLEANINGS, GPM

FREQUENCY AND DURATION OF CLEANING

REMARKS

5. REHEATER

TYPE (DIRECT, INDIRECT) Direct Oil Fired

b) For floating bed, packing thickness at rest.

DUTY, MMBTU/HR _____

HEAT TRANSFER SURFACE AREA SQ.FT _____

TEMPERATURE OF GAS: IN _____ OUT _____

HEATING MEDIUM SOURCE No. 2 Oil

TEMPERATURE & PRESSURE _____

FLOW RATE 7.3gal/min LB/HR

REHEATER TUBES, TYPE AND MATERIAL OF CONSTRUCTION _____

REHEATER LOCATION WITH RESPECT TO DEMISTER Downstream of Demister prior to scrubber stack entrance

METHOD OF CLEANING _____

FREQUENCY AND DURATION OF CLEANING _____

FLOW RATE OF CLEANING MEDIUM _____ LB/HR

REMARKS Problems with oil pumps, burners and temperature control so far very little operation

6. SCRUBBER TRAIN PRESSURE DROP DATA

	INCHES OF WATER
PARTICULATE SCRUBBER	
SO_2 SCRUBBER	
CLEAR WATER TRAY	
DEMISTER	2"
REHEATER	
DUCTWORK	
TOTAL FGD SYSTEM	

7. FRESH WATER MAKE UP FLOW RATES AND POINTS OF ADDITION

TO: DEMISTER Service Water (Clarifier)

QUENCH CHAMBER Service Water (Clarifier)

ALKALI SLURRYING Service Water (Clarifier)

PUMP SEALS Service Water (Clarifier)

OTHER Service Water (Clarifier)

TOTAL Make-up service water to thickener overflow tank from river.

FRESH WATER ADDED PER MOLE OF SULFUR REMOVED 180

8. BYPASS SYSTEM

CAN FLUE GAS BE BYPASSED AROUND FGD SYSTEMS Blank off Yes, But not automatic

GAS LEAKAGE THROUGH BYPASS VALVE, ACFM No bypass valve

K. SLURRY DATA

	pH	% Solids	Capacity (gal)	Hold up time
LIME/LIMESTONE SLURRY MAKEUP TANK				
PARTICULATE SCRUBBER EFFLUENT HOLD TANK (a)				
SO_2 SCRUBBER EFFLUENT HOLD TANK (a)				

L. LIMESTONE MILLING AND CALCINING FACILITIES: INDICATE BOILERS SERVED BY THIS SYSTEM.

TYPE OF MILL (WET CYCLONE, ETC.) Dravo, Gibbs & Hill

NUMBER OF MILLS

CAPACITY PER MILL T/HR

RAW MATERIAL MESH SIZE

PRODUCT MESH SIZE

SLURRY CONCENTRATION IN MILL _____

CALCINING AND/OR SLAKING FACILITIES _____

SOURCE OF WATER FOR SLURRY MAKE UP OR SLAKING TANK _____

M. DISPOSAL OF SPENT LIQUOR

1. SCHEMATICS OF SLUDGE & FLY ASH DISPOSAL METHOD

(IDENTIFY QUANTITIES OR SCHEMATIC) _____

2. CLARIFIERS (THICKENERS)

NUMBER 2

DIMENSIONS 75' diameter

CONCENTRATION OF SOLIDS IN UNDERFLOW 30-40%

3. ROTARY VACUUM FILTER

NUMBER OF FILTERS _____

CLOTH AREA/FILTER _____

CAPACITY _____ TON/HR (WET CAKE)

CONCENTRATION OF SOLIDS IN CAKE _____

PRECOAT (TYPE, QUANTITY, THICKNESS) _____

REMARKS _____

4. SLUDGE FIXATION

POINT OF ADDITIVES INJECTION Mixing tank prior to sludge holding pond

FIXATION MATERIAL COMPOSITION _____

FIXATION PROCESS (NAME) Calcilox (Dravo)

FIXATION MATERIAL REQUIREMENT/TONS OF DRY SOLIDS OF SLUDGE

Nominal 10%

ESTIMATED POND LIFE, YRS. _____

CONCENTRATION OF SOLIDS IN FIXED SLUDGE _____

METHOD OF DISPOSAL OF FIXED SLUDGE Truck haul to land fill

INITIAL SOLIDIFICATION TIME OF FIXED SLUDGE _____

5. SLUDGE QUANTITY DATA

POND/LANDFILL SIZE REQUIREMENTS, ACRE-FT/YR _____

IS POND/LANDFILL ON OR OFFSITE Off-site

TYPE OF LINER Hypalon on demonstration pond only

IF OFFSITE, DISTANCE AND COST OF TRANSPORT N/A

POND/LANDFILL DIMENSIONS AREA IN ACRES N/A
DEPTH IN FEET N/A

DISPOSAL PLANS; SHORT AND LONG TERM _____

N. COST DATA

1. TOTAL INSTALLED CAPITAL COST $33,000,000 Phase I, Phase II $7,000,000

2. ANNUALIZED OPERATING COST without fixed charges Phase I is $5,000,000 Phase II 7,273,000
Including fixed charges Phase I 10,000,000 Phase II 13,661,000

3. COST BREAKDOWN

	COST ELEMENTS	INCLUDED IN ABOVE COST ESTIMATE		ESTIMATED AMOUNT OR % OF TOTAL INSTALLED CAPITAL COST
		YES	NO	G & H
A.	CAPITAL COSTS			
	SO_2 SCRUBBER TRAINS	[X]	[ ]	
	LIMESTONE MILLING FACILITIES	[X]	[ ]	
	SLUDGE TREATMENT & DISPOSAL POND	[X]	[ ]	
	SITE IMPROVEMENTS	[X]	[ ]	
	LAND, ROADS, TRACKS, SUBSTATION	[X]	[ ]	
	ENGINEERING COSTS	[X]	[ ]	
	CONTRACTORS FEE	[X]	[ ]	
	INTEREST ON CAPITAL DURING CONSTRUCTION	[X]	[ ]	
*B.	ANNUALIZED OPERATING COST			
	FIXED COSTS			
	INTEREST ON CAPITAL	[X]	[ ]	
	DEPRECIATION	[X]	[ ]	
	INSURANCE & TAXES	[X]	[ ]	
	LABOR COST INCLUDING OVERHEAD	[ ]	[X]	
	O & M COSTS			
	LABOR	X		7.5%
	RAW MATERIAL	[X]	[ ]	20.5%
	UTILITIES	[X]	[ ]	19.0%
	MAINTENANCE	[X]	[ ]	15.5%
	DISPOSAL	X		37.5%

* Based on full SO_2 removal to meet regulations of 0.6 lb SO_2/million BTU emissions.

4. COST FACTORS

a. ELECTRICITY X

b. WATER N.A.

c. STEAM (OR FUEL FOR REHEATING)

d. FIXATION COST N/A $/TON OF DRY SLUDGE

e. RAW MATERIAL PURCHASING COST $/TON OF DRY SLUDGE

f. LABOR: SUPERVISOR HOURS/WEEK WAGE

OPERATOR

OPERATOR HELPER

MAINTENANCE

5. MAJOR PROBLEM AREAS: (CORROSION, PLUGGING, ETC.)

1. SO_2 SCRUBBER, CIRCULATION TANK AND PUMPS.

a. PROBLEM/SOLUTION

Deposits on skirts of scrubber, Gusset Plate

Throat Damper

Under Upper Cone

Bleed Valves

Recycle Pumps

2. DEMISTER

PROBLEM/SOLUTION

Lime Deposits

3. REHEATER

PROBLEM/SOLUTION

Pumps, Blowers, Temp. Control

4. VENTURI SCRUBBER, CIRCULATION TANKS AND PUMPS

PROBLEM/SOLUTION

Recycle pumps 33% Impeller and casing erosion in 3000 hrs
Better volute design, possibly rubber line pumps

5. I.D. BOOSTER FAN AND DUCT WORK

PROBLEM/SOLUTION

Dampers Corrosion - Ceilcote same

Fan Yield strength, corrosion - rubber line shaft, Internal Wash

Exp. Joint Asbestos-Butyl compound material for joints better than s.s.

Fan Strength, Weld mat overlay install doubler plates to reduce operating yield strength

6. LIMESTONE MILLING SYSTEM OR LIME SLAKING

PROBLEM/SOLUTION

Degritting - No redundancy 10% down time
better if indoor operation, spare capacity

7. SLUDGE TREATMENT AND DISPOSAL

PROBLEM/SOLUTION

Land Over 1000 ton/day sludge disposal required, Purchase and Development

Leachate Still not known if leachate is acceptable more testing required.

8. MISCELLANEOUS AREA INCLUDING BYPASS SYSTEM

PROBLEM/SOLUTION

Instrumentation need good pH cells, constant attention, stack opacity monitor useless
Boiler Instrument

Stack

Noise Fan noise and associated equipment

Instrumentative Sump pumps high erosion wear

P. DESCRIBE FACTORS WHICH MAY NOT MAKE THIS A REPRESENTATIVE INSTALLATION What is representative? No such thing

Possibly Land limitations

Q. DESCRIBE METHODS OF SCRUBBER CONTROL UNDER FLUCTUATING LOAD. IDENTIFY PROBLEMS WITH THIS METHOD AND SOLUTIONS. IDENTIFY METHOD OF pH CONTROL AND LOCATION OF pH PROBES.

Boiler gas flow fed into damper control and venturi throat damper control. System has worked ok, but because plant has only recently run with all boilers connected to scrubber, we have had insufficient time to observe. Have lost trains occasionally pH is controlled by maintaining scrubber recycle solution at a given level.

APPENDIX B

PLANT PHOTOGRAPHS

Photo No. 1 General view of the Phillips Power Station from the sludge disposal area. The scrubber stack appears at the center of the picture.

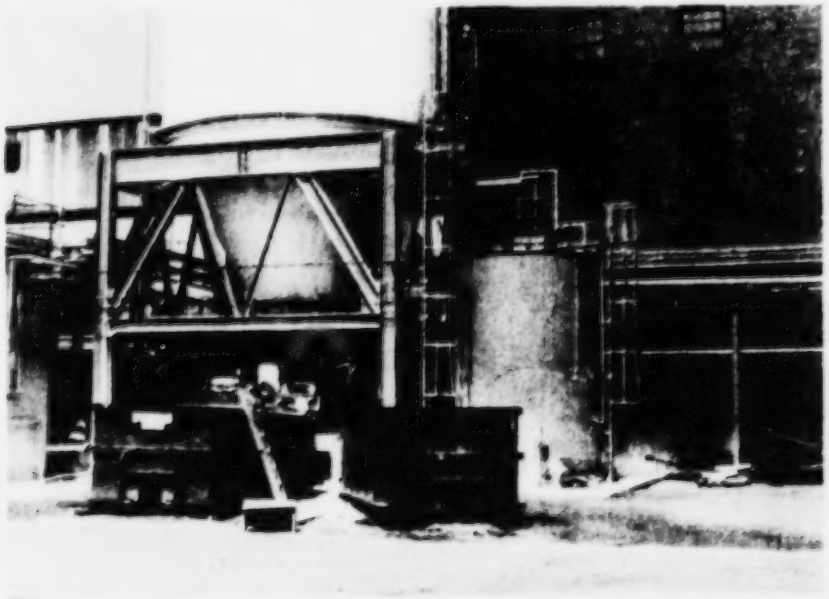

Photo No. 2 View of the Phillips lime storage tank and slaking facility. The storage tank has a -day capacity of pounds of lime.

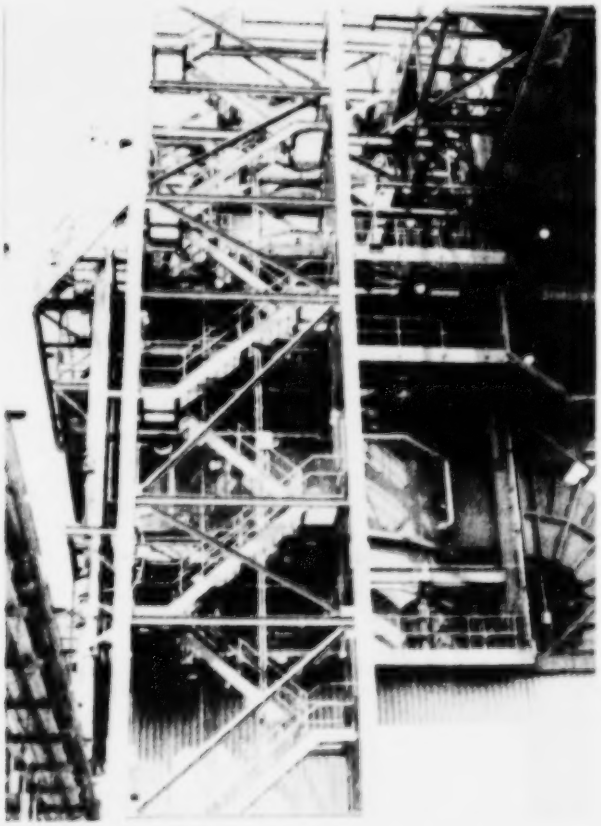

Photo No. 3 View of the Phillips FGD scrubber module is almost completely obscured by structural steel. Gas inlet duct appears at the right side slightly below the center of the picture.

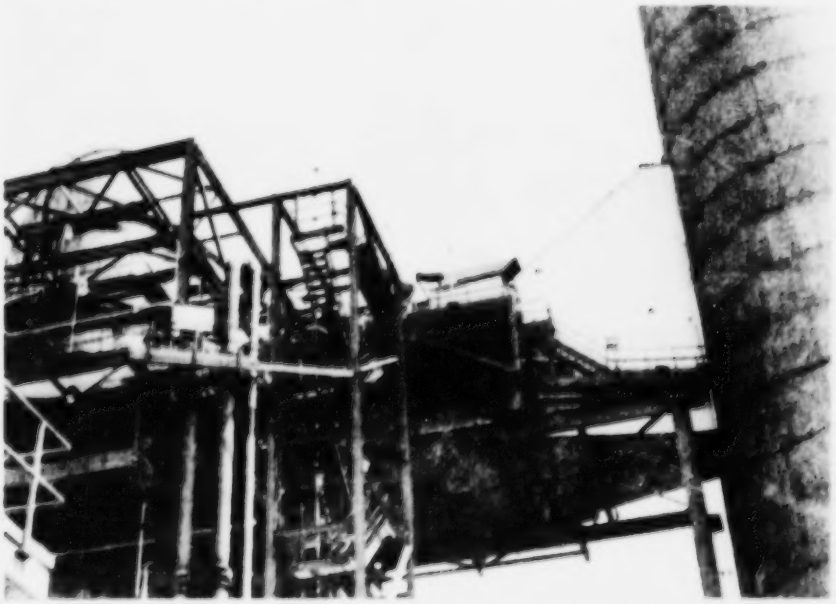

Photo No. 4 View of ductwork between scurbber and stack. The direct-fired reheater is located immediately to the right of the scrubber module.

Photo No. 5 View of Phillips FGD scrubber recirculating pumps.

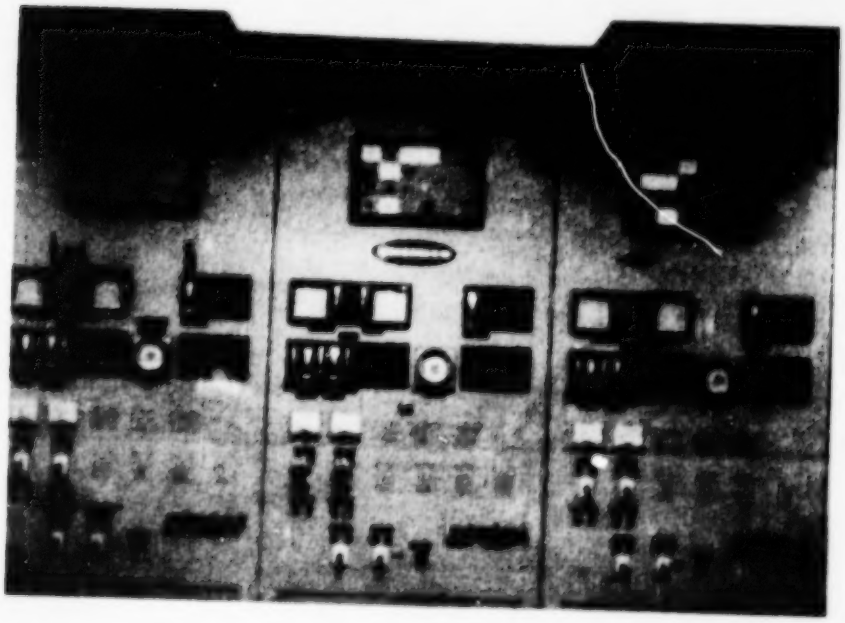

Photo No. 6 View of the Phillips scrubber control panel.

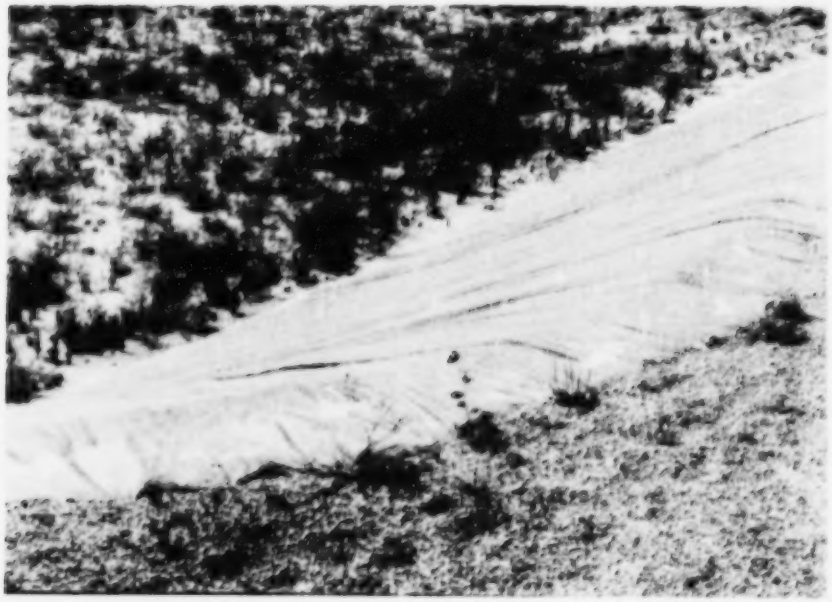

Photo No. 7 View of edge of empty Phillips sludge disposal pond showing plastic barrier liner which surrounds the pond. Leachate collection pipes are installed in the bottom of the pond for sampling and analysis.

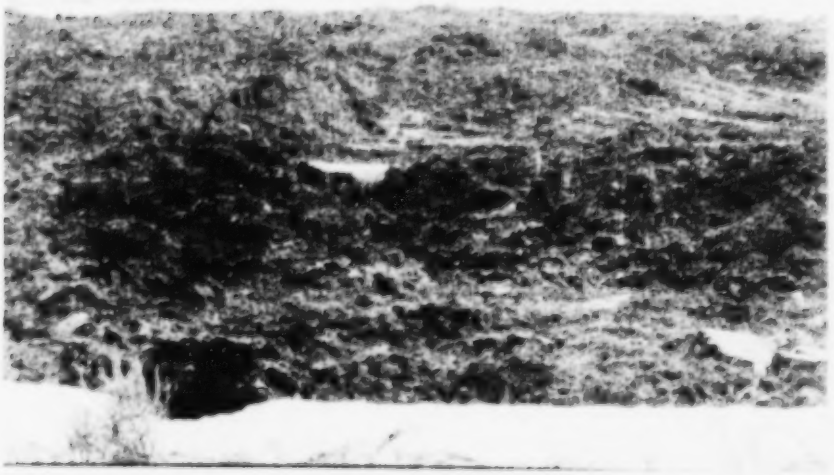

Photo No. 8 Stabilized sludge in Phillips test disposal pond. Barrier liner at perimeter can be seen in foreground and background.

APPENDIX C

OPERATIONAL REPORT

DUQUESNE LIGHT COMPANY
PHILLIPS POWER STATION
LIME SCRUBBING FACILITY

By

Steve L. Pernick, Jr
Manager-Environmental Affairs
Duquesne Light Company
Pittsburgh, Pennsylvania

and

R. Gordon Knight
Superintendent-Technical Services
Duquesne Light Company
Pittsburgh, Pennsylvania

Prepared for presentation
at
EPA Flue Gas Desulfurization Symposium
Atlanta, Georgia
November 4-7, 1974

DUQUESNE LIGHT COMPANY
Phillips Power Station
Lime Scrubbing Facility

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DUQUESNE LIGHT COMPANY
Phillips Power Station
Lime Scrubbing Facility

INTRODUCTION

Duquesne Light Company is an investor-owned electric utility serving approximately 1/2 million customers in southwestern Pennsylvania including Pittsburgh. The Company has a net generating capability of approximately 2700 MW and presently operates three coal burning power stations, two of which, Phillips and Elrama, are discussed in this paper.

In 1969, Gibbs & Hill, Inc. was engaged to conduct a comprehensive study of the most feasible means of complying with: the emission regulations being promulgated at the time by Allegheny County, which has control over the Phillips Station; the regulations of the Commonwealth of Pennsylvania, which has jurisdiction over the Elrama Station, and the most stringent regulations that could reasonably be conceived. The study was completed in September, 1970. It represented a comprehensive evaluation of all test data concerning emissions from the two power stations and an intensive investigation of all possible means of compliance with the applicable and anticipated regulations. The study concluded that: (1) the use of low sulfur western coal was not a feasible means of compliance since it would not achieve compliance with the particulate emission limitations of the regulations with the existing dust collection equipment; (2) that conversion from coal to low sulfur oil was not feasible due to the uncertainties of obtaining a sufficient supply of the necessary large quantities of such oil; and (3) that the most practical means of sulfur dioxide emission control was desulfurization of stack gases. The consultants then conducted a thorough study of existing methods of sulfur dioxide removal from stack gases. At the time of their investigation in 1969 to 1970, only two full scale stack gas scrubbing systems were in operation in the United States. One of these has since been abandoned and the second has had a poor record of operating reliability. Furthermore, the injection of limestone directly into the boiler, which was the basis of these SO_2 removal processes, was not at all suitable for consideration at the Elrama and Phillips Power Stations since it would result in additional boiler tube erosion to which the boilers were already particularly susceptible. Furthermore, available data indicated that SO_2 removal efficiency might not be sufficiently high to comply with the regulations which were among the most stringent in the country.

Because of the characteristics of our boilers and our requirements for a system that would remove both particulates and sulfur dioxide, the report concluded that a tail-end scrubbing system was the best available means of control and recommended that we install a dual stage venturi scrubbing system. Some of the technical

reasons for choosing the system are as follows:

1. It was thought that a dual stage scrubbing system would enable separating the sludges resulting from scrubbing for fly ash in the first stage and scrubbing for SO_2 in the second stage, in the event the sludge from the SO_2 removal stage became a problem.

2. A dual stage scrubber had the potential of being converted to a magnesium oxide regenerative system in the event it became desirable or practical to do so.

3. Venturi scrubbing for particulate removal was fairly well proven in the steel industry. Furthermore, if only one of the scrubber trains was equipped with a dual stage SO_2 prototype, and this was proved to be impractical or unworkable, we would still have a workable single stage venturi scrubber system for particulate removal. We could then investigate an alternate method of SO_2 removal with minimal loss of investment.

In addition to the above reasons was the fact that preliminary time schedules indicated that these scrubbers could be delivered with the least delay. Duquesne accepted the recommendations of Gibbs & Hill, and in view of the unproven nature of the wet scrubbers for sulfur dioxide removal, decided that the most prudent approach to the installation was to begin by equipping only a portion of the scrubber system at the Phillips Station with sulfur dioxide removal equipment. Subsequently, Gibbs & Hill was instructed in September, 1970, to proceed with the designing and installation of the Phillips scrubber system. The scrubber installation at this plant was to include four scrubber trains. Three of these were single stage scrubbers for dust removal, and one was a dual stage scrubber (two single stages in series) which is the prototype for sulfur dioxide removal. Each scrubber was to be capable of approximately 540,000 CFM, which is the equivalent of approximately 125 megawatts. With the station rated at 387 megawatts, this meant that the station would be equipped with essentially a spare scrubber train. This was a criterion specified by Duquesne Light Company to assure sufficiently high availability of the system.

It was anticipated that after a trial period, the operation of the prototype would serve as a basis for decision as to the installation of additional similar SO_2 removal equipment at this station and other coal burning facilities to comply with the applicable regulations.

PILOT PLANT OPERATION

In February, 1971, a pilot plant size Chemico venturi type, dual stage scrubber system with a capacity of 1500 CFM was installed at the Phillips Power Station to study the performance and operating characteristics of the dual stage venturi scrubber system. The pilot

plant was connected to the duct entering the mechanical dust collector of No. 5 boiler. The scrubber was operated with various types of limestone and lime. In addition, other conditions such as the stoichiometry, liquid to gas flow ratio and pressure drop were varied in order to determine the conditions which would yield optimum collection efficiency and operating conditions. After determination of these parameters in approximately 3 months of operation, the pilot scrubber was dismantled on May 8, 1971.

In the meantime, in March, 1971, invitations to bid were issued by Duquesne Light Company to Chemico and Combustion Engineering for a scrubber system capable of removing sufficient SO_2 and particulates to comply with existing and anticipated future regulations. The bid was subsequently awarded to the Chemico Corporation in July, 1971. The battery limits for Chemico was limited to the scrubbers and associated pumps and controls between the inlet hot gas duct manifold to the exit wet gas header, including the reheater but excluding the new induced draft fans.

In obtaining approval of our plan, compliance programs were negotiated with Allegheny County for the Phillips Station and with the State for the Elrama Power Station. The program included the installation of five single stage venturi scrubbing trains for particulate removal only at the Elrama Station, to be installed concurrently with the Phillips scrubber system as described above. The plan was to use the prototype sulfur dioxide removal installation at Phillips as a basis for decisions concerning additional SO_2 removal equipment at both stations in order to comply with SO_2 emission limitations.

INSTALLATION SCHEDULE

Although in Duquesne's best judgment, the scrubber system could not be made operational, even for particulate removal, prior to July 1, 1973, which was 34 months from the date of our decision to install a scrubber system, Duquesne Light eventually acceded to pressure from the State of Pennsylvania and established a target date of January 1, 1973. Following startup, the schedule called for a two-month "debugging" period followed by a ten-month test program on the prototype SO_2 scrubber at Phillips. This would determine if stack gas scrubbing with alkaline injection on a plant scale basis was a feasible and reliable means of removing sulfur dioxide from the gases. The plan was to study operating conditions during this period to establish optimum SO_2 removal efficiency using various types of lime, the operating mode most conducive to reliable trouble-free operation, and other essential information. The schedule called for a decision to be made by January 1, 1974, as to whether or not the operation of the prototype SO_2 scrubber was satisfactory or if an alternate system should be investigated. If the operation of the prototype sulfur dioxide scrubber proved satisfactory, the schedule called for design, procurement and installation of additional SO_2 removal equipment by January 1, 1978, for both stations. At that time, compliance with County and State regulations would be achieved. (For a list of significant dates see Figure 5)

Despite our best efforts, no part of the Phillips scrubber installation was placed in operation until July 9, 1973, and then for only two boilers. At that time, two of the scrubber trains were placed in operation, and two of the six boilers were connected to the scrubber system. This was consistent with our startup schedule which called for connecting one boiler at a time to the scrubber system so as not to jeopardize the availability of a significant portion of the plant's generating capability in the event of failure of the scrubber system. The two boilers connected have a combined steam generating capability equivalent to approximately 80 megawatts.

The July 9, 1973 startup date represents a slippage of approximately 6 months from the original schedule. This slippage was attributable to the following factors:

1. The venturi scrubber system was not a completely engineered system at the tine it was purchased, and a considerable amount of developmental engineering was required to adapt the scrubbers to a system that would meet our requirements. Chemico was also charged to incorporate, to the limits of their responsibility the latest available operating and maintenance experiences at the Four Corners Plant in New Mexico, the Dave Johnston Plant in Wyoming, Mitsui Plant in Japan, and any other Chemico installation having experiences adaptable to our proposed installations.

2. Equipment suppliers and fabricators did not meet promised delivery dates due to the volume of orders, decreased productivity, and inadequate quality control. Considerable money was spent to expedite and inspect equipment and materials for our project. In spite of this effort and expense, many late deliveries and mistakes in fabrication occurred. Some examples are as follows:

   a. The induced draft fans were scheduled for delivery in Phillips by July 15, 1972. Delivery was not completed until December 12, 1972, a delay of five months. Not only were the fans late, but numerous cracks and defects in the welds on the fan rotors were found after delivery. It was necessary to grind out all of the defective welds and make the necessary repairs in the field.

   b. An approximate five-month delay was experienced in delivery of the ductwork. In addition, because of the huge size and weight of the ductwork, many structural support schemes had to be studied before an acceptable method of reinforcing the existing station building to accept the unusual weight load of the ductwork could be determined. After a reinforcement plan was devised, errors were discovered in the implementation of the plan, requiring corrective design work.

c. Delays of up to six months were experienced in the delivery of electrical equipment such as switchgear and transformers. In addition to the delay of equipment, errors were found in the wiring diagrams for this equipment. Once the equipment was received, design errors were also discovered, such as improperly designed bus connections on the switchgear and improper alignment of bus bars on power centers. In addition, failures of switchgear and transformers were experienced during field testing.

These are only a few examples of the numerous delays and errors by equipment suppliers which affected the final completion date of the first phase of the Phillips project.

3. Major delays were also incurred in the field, such as the following:

a. Because of engineering delays and late delivery of equipment, construction schedules had to be continually revised which seriously affected productivity.

b. Space limitations existing at the job site, more serious than anticipated, affected productivity because of the lack of accessability and maneuverability. Special equipment and construction methods for the installation of the equipment were required beyond those originally anticipated, thus contributing to additional delays.

c. The availability of boiler outages for tie-in of the new ducts, presented additional problems. Outages had to be scheduled months in advance, and any revision in schedule was dependent upon availability of purchased power and the outage schedules of other generating equipment, both on our system and on interconnections.

DESCRIPTION OF SYSTEM

Design of both the Phillips and Elrama systems was a joint effort by Gibbs & Hill and Chemico, each having certain battery limits. Construction was the responsibility of Gibbs & Hill. Only the Phillips system will be described in detail.

The Phillips system comprises four parallel trains, Figure 1, and was designed to handle a total gas volume of 2,190,000 ACFM with all trains in service. With one train out of service, the three trains have a capacity of 1,600,000 ACFM, which is sufficient for 400 MW, assuming normal excess air.

Three scrubber trains were provided with first stage scrubbing for fly ash removal, Figure 2. The fourth train, known as the "prototype" SO_2 train, was fitted with a first stage particulate removal scrubber[2] and a second stage SO_2 absorption scrubber as shown on Figure 3.

The ductwork on each boiler was modified to enable operation with the gases going either to the scrubbers or to the original gas path after passing through the existing dust collection equipment. A mechanical and electrical dust collector are located in series ahead of each individual boiler stack. The existing ducts leading to the old ID fans and stacks were blanked off with removable steel plates to enable diversion of the flue gas to a new common duct. The new ductwork is routed to the scrubber building where 16 foot diameter takeoffs lead to each of the four first stage scrubbers.

The hot flue gas (about 340°F) containing fly ash and sulfur dioxide (about 1400 ppm SO_2) enters the first stage scrubber and impinges upon the upper cone. One half of the total scrubber liquor (8250 gpm) is introduced, Figure 4, into the vessel through the bull nozzle where it is sprayed over the surface of the upper cone, to initiate the scrubber action. A second stream of 8250 gpm scrubber recycle liquor enters through the tangential nozzles at a point above the adjustable throat damper. The flue gas and scrubbing liquor are brought into intimate contact in the throat section of the scrubber where the particulates and some SO_2 are removed. The gas and liquor continue downward to the separator section where, after being separated from the scrubbing liquor, the flue gas enters a demister where entrained liquor is removed. The gas leaves the scrubber and enters a new wet ID fan which is provided with water sprays to remove any accumulation of solids resulting from carryover from the scrubber. Fresh water is used for spraying.

The ID fan housings are lined with 1/4 inch thick natural rubber. Wheel material is Carpenter 20 Cb 3. The shaft is 316 L stainless steel. Each fan is driven by a 5500 HP, 1200 RPM, 4160V electric motor. Bearings are of the water-cooled type, served from a closed cooling water system.

Outlet gas temperature, normally 110-120°F, from the first stage scrubber is monitored. At 175°F a control valve is automatically opened to admit emergency cooling water to the upper cone. Additional temperature rise would automatically shut down the fan and close the isolation dampers.

The gas leaving the ID fan enters one of two vessels depending on the train. In the case of the three single stage scrubber trains, the gas enters an entrainment separator in which entrained water is separated and collected. The separators or mist eliminators are separate vessels which will be replaced by second stage scrubber vessels if the test program indicates this to be necessary. In the

case of the SO_2 prototype train, gas leaving the ID fan enters a second stage scrubber vessel, which is identical in size and design to the first stage. This second stage vessel is equipped with a reagent (lime) injection nozzle in the bottom cone. The scrubbing liquor is then picked up by the two recycle pumps (Carpenter 20 Cb 3). Some of the liquor is bled off to the first stage scrubber, where some is removed from the cycle to thickeners, and the balance is recycled.

Total recycle flow is about 16,500 gpm with a 615 gpm bleed to the thickeners. All single stage vessels have also been fitted with reagent nozzles and feeds to enable control of pH and incidental SO_2 removal.

The exit gases leaving either the second stage scrubber vessel or the mist eliminator vessel enter a common wet duct lined with Flakeline 103 (a product of the Ceilcote Company consisting of a glass flake filled modified polyester resin, subsequently referred to as Ceilcote) which leads to a new concrete acid resistant brick lined chimney. Prior to entering the 340 foot chimney, a section of the wet gas duct, constructed of 316L SS is equipped with a reheater, employing a direct oil-fired burner system. The two-burner system is capable of reheating 30°F, although the intent is to normally reheat 20°F.

Bleed off from all scrubbers is directed to a trough feeding two 75 foot diameter thickeners. The overflow from these thickeners is directed to a collecting tank where it is pumped by two-2000 gpm SS pumps to the make-up line for return to the scrubber system.

Thickener underflow, at 35 to 40% solids concentration, is pumped by one of two 105 gpm, 15 HP pumps to one of three clay lined sludge holding ponds. Each pond has a capacity of about 6500 cubic yards. Just prior to discharge to the holding ponds, the sludge enters a mixing tank where a stabilizing agent can be added at a predetermined rate based on the density of the sludge as it leaves the thickener. After the additive is intimately mixed with the sludge, the mixture discharges by gravity to one of the ponds.

In the pond, both settling and curing take place. Supernatant liquid is withdrawn and recirculated to the scrubber system via the thickener. The sludge curing ponds provide interim storage while stabilization is taking place. One pond received thickener underflow, while a second is curing and the third is being excavated for final off-site disposal.

Lime is fed from a storage silo at a controlled rate to the lime slaker where it is slaked with fresh make-up water. The slaked lime overflows into a slaker transfer tank, where make-up water is added to provide a constant flow of lime slurry with a concentration of about 15%.

A service (river) water system independent from the power station service water system is provided. It includes a pair of 900 gpm, 100 HP pumps taking suction from the existing condenser discharge tunnel and a 10 inch distribution header for the scrubber facility. It provides fan spray water, pump seal water, mist eliminator and scrubber demister spray water, instrumentation flush water, chemical mixing tank, and emergency water for scrubbers.

INITIAL OPERATION

Although the lime addition system was not yet completed, partial start-up of the scrubber system began on July 9, 1973. The decision to proceed with startup, without the lime addition system, was made in light of the fact that we thought the scrubber system was suitable for operation at a low pH. Almost all of the major components and piping were either Ceilcoted, rubber lined or fabricated of a corrosion resistant material to withstand a low pH. During the first five days of operation, a pH of approximately 1.3 to 2.0 developed in the scrubbing liquor while burning 1.8-2.0% sulfur coal. Because of pressure to proceed with the debugging operation, and because of our reluctance to incur additional delays, the decision was made to continue operation with the low pH rather than shut down the scrubbers until the lime system became operational. Unfortunately, as a result, the scrubber system was forced out of service due to the corrosion failure after five days of the two thickener overflow return pumps, which were intended for operation at a pH of 5 to 6. They were promptly replaced with two 316 I SS pumps. Use of the lime system feed to the thickeners was obtained after the first week of operation.

During the first two weeks of operation, additional problems developed and were corrected in a two-week outage following the first two weeks of operation:

1. A piece of rubber liner was found in the suction of one of the recycle pumps. The individual scrubber was shut down in an effort to locate the source; however, it could not be determined until the corrosive nature of the scrubber media caused the failure of a 20 5/16" line within 10 days.

2. Leaks occurred in the lead floor lining of the stack which were a potential threat to the stack concrete structure. The lead sheets had been soldered rather than "burned." The lining was replaced.

3. Leaks developed in four 40' SS expansion joints in the gas ducts leading to the stack. The appearance of the failed metal was variously described as that of "lace curtain" or "swiss cheese." This resulted from partial-load type of operation of the scrubber system requiring us to partially open the vacuum breakers and allow ambient air

to supplement the gas flow through the scrubbers. Condensation resulted. The joints were replaced with an asbestos/butyl material.

4. The reheater, which utilizes direct firing of No. 2 oil in the cold gas duct as it enters the stack, is not yet operational. We have been unable to obtain satisfactory operation of the reheater due to burner problems and oil pump problems. We have placed no priority on solving these problems due to our reluctance to operate the reheater considering the present energy crisis and oil shortage. Whenever the reheater becomes operational, we plan to operate it during periods of adverse meteorological conditions to obtain a higher effective stack height.

5. During the outage, evidence of corrosion was found on the ID fan shaft shrouds, inlet dampers and stiffener bars - all 316 L stainless steel. Two corrective measures were taken - redesign of the fan sprays and application of 1/4-inch rubber coating to the affected parts. After two weeks of operation the chloride concentration in the liquor (closed cycle)had reached 800-900 ppm. This, no doubt, contributed to the corrosion noted above. It was eventually to reach 3500-4500 ppm.

On August 5, 1973, the scrubber system was returned to service with the lime feed system for pH control continuing in operation. In addition to No. 1 and No. 2 boilers, the No. 3 boiler was also connected to the scrubber system, which made a total of approximately 145 megawatts.

During the following weeks of operation, we were informed by Chemico of a major change in the operating requirements of the scrubbers; namely, the necessity to bleed more fluid to the thickener tanks so that the concentration of solids in the recycling fluid could be kept to a minimum in order to protect the recycle pumps, and to minimize the settling of solids in the bleed lines. This caused a change in the design concept by essentially doubling the bleed rate. This meant that the two 900 gpm thickener tank overflow return pumps, which had been provided with the system, were inadequate since they no longer had sufficient capacity to supply the needs of the scrubber system under one pump operation (the second being a spare) with all boilers connected to the scrubber system. Two 2000 gpm pumps were obtained for later installation in parallel with the two 900 gpm pumps.

During the two months of operation following the August 5, 1973 start-up date, operation of the scrubbers was alternated between trains. In other words, as problems arose on one train, it was shut down and another train was put in service to take its place. No effort was made to operate the dual stage prototype SO_2 scrubber for full SO_2 removal because it was felt that debugging operations could more effectively proceed with the most basic operation possible, in other words,

with the single stage scrubbers.

EXTENDED SHUTDOWN FOR REPAIRS

During the operation of the scrubbers in August and September, 1973, additional problems came to light which caused an extended shutdown of the scrubber system, and a further delay in the operating schedule, namely:

1. A routine inspection of the new stack revealed additional moisture leaks from condensation (pH 2.0) seeping through the mortar joints and running down the outside of the acid brick lining. Seepage was occurring in more than 100 areas of the brick lining. The condensate was collecting at the bottom of the stack in the annulus between the lining and the shell. The acid condensate was also seeping through construction joints and down the outside of the concrete shell permitting it to attack the concrete, which could possibly impair the structural stability of the stack. The contractor advised us that a four week outage would be necessary to permit inspection of all mortar joints and to repoint as required. This outage for other reasons to be described, extended for about five months.

2. Significant scaling and buildup had occurred in various portions of one or more of the scrubbers and in the associated piping in varying degrees as described below:

   a. Buildup was found on many of the upper cone support struts. These football-size accumulations appeared to be creating a disturbance in the water flow pattern over the cone resulting in accumulations of deposit on the cone surface.

   b. Deposits were found in the throat area of two of the scrubbers, sufficiently thick in some areas to prevent the maintenance of the six inch design pressure drop across the throat.

   c. A thin buildup of hard scale was observed on the face of the throat dampers of one of the scrubbers.

   d. Deposits of fly ash were found in and around the operating mechanisms of the adjustable throat dampers. These were sufficient to prevent full adjustment of the dampers.

3. Corrosion/erosion was found in numerous areas:

   a. Severe pitting and corrosion appeared on all of the 316 L clad ID fan damper blades and frames. The cladding was

removed and the carbon steel was Ceilcoted.

b. In all scrubbers, a moist layer of fly ash was observed on the carbon steel skirt that directs the flue gas down the cone. Extensive rusting was found under the fly ash and on the underside of the vessel tap as well. The latter may have resulted from frequent outages for inspection, during which alternate wetting and drying occurred.

c. The upper cones of the scrubber vessels were fabricated with a 316 L SS apex. The balance was carbon steel with a Ceilcote coating. The uncoated apex showed erosion/corrosion in all vessels. Similar attack was shown on the inner surface of the 316 L bull nozzle directly above the cones. Both affected areas were coated during the outage.

d. Baffle plates in some tangential nozzles (12 per vessel) were found badly corroded. The specified material of construction was 316 L SS, but it was found that the corroded baffles had been fabricated of 304 SS. Sixteen baffles out of a total of 60 required replacement with 316 L.

e. Similarly, the throat damper arms (12 per vessel) were supposed to be 316 L SS. Thirty-two out of a total of 60 were badly corroded and were found to be 304 SS. They were replaced with 316 L.

f. The top and bottom throat damper scraper blades were practically destroyed. The also were found to have been 304 SS instead of 316 L. They were replaced with 316 L.

4. An initial inspection and analysis of the ID fans by Franklin Institute Research Laboratory (FIRL) indicated the existence of chloride stress corrosion cracking of the parent metal and structural welds, as well as general corrosion on all exposed surfaces. At that time, they advised us that the problems resulted from the hostile environment in which the fans were operating. In addition, they made a specific recommendation that the fans not be operated in the condition found at that time, due to possible catastrophic failure.

As a result of their search for protective coatings, FIRL recommended the application of a Ceilcote material, Coroline 505AB. This is a hard, impervious, acid resistant, epoxy base material which is applied at a nominal thickness of approximately 1/4". The application of the Coroline is a tedious, time consuming hand application by trowel and requires close

quality control. The application of the material began in November, 1973. Although Coroline had not been extensively used on fan blades, or proven to any degree, we were given reasonable assurance that it would be successful. As a result, we began application of this material to as many fans as manpower permitted.

On January 22, 1974, the first fan was completely coated and was started up for balancing. After a balance move was attempted, the fan was forced out of service due to excessive vibration resulting from separation of a portion of the coating from one of the blades. The Ceilcote Company informed us that the separation was localized and probably caused by a faulty batch of material which did not properly adhere to the metal. The Coroline was re-applied and the fan was started again on February 5, 1974 and again was forced to shut down due to separation of the material in a second area. At that time, the Ceilcote Company was unable to adequately explain the failure of the coating to adhere to the fan surfaces. As a result, the decision was made that the application of Coroline as protection against the adverse effects of the flue gases was not the answer to the problem. It is believed that the flexing of the blades during operation may have contributed to the lack of adhesion between the Ceilcote and the blades.

By this time, FIRL had been able to conduct more exhaustive investigations and analyses on the fan blade material. As a result, they revised their initial conclusion and reported that the fans were suffering from a much lesser degree of stress corrosion cracking of the weld metal and a degree of pitting attack on all fan blades. The report also indicated that fan failure was no longer considered imminent.

In review of the ID fan problems, it appears that the corrosion problems which we had experienced might be partially due to the operation of the scrubber system at a lower pH and a higher chloride concentration (3500-4500 ppm) than had been foreseen by the scrubber designers. Several steps were taken to try to alleviate the situation:

1. Operation of the dual stage scrubber with full lime addition, which we felt would be adequate for maintaining optimum pH control in that train;

2. Addition of supplemental lime feed to the other operating scrubbers, and

3. The installation of a redesigned spray system, which had proven effective at other installations.

These steps in addition to frequent scheduled fan inspections were felt to be adequate safeguards for placing the system back in operation.

Our ability to start up the scrubber system and initiate full SO_2 removal in the dual stage prototype was further improved by the completion of the sludge stabilizer addition system. We had been reluctant to add large quantities of lime to the single stage scrubbers, and equally reluctant to begin operation of the dual stage scrubber, both of which result in the production of considerable amounts of sulfate sludge, without the capability of adding a stabilizer.

SECOND START-UP OPERATION

Removal of the Coroline material from the dual stage scrubber fan No. 1 was completed, and startup of the scrubber system once again began March 17, 1974. At that time, the dual stage Scrubber Train No. 1, and Scrubber Train No. 4 were placed in operation with boilers No. 3 and 4 connected to the scrubber system. Since then there have been these additional developments:

1. Excessive Fly Ash

The sludge handling system was designed so that after 30 days of normal operation with all boilers tied in and with the dual stage SO_2 prototype and two of the three single stage scrubbers, the first curing pond should be approximately full. However, after the first two weeks, one pond was completely filled with only two boilers connected to the scrubber system during the first week and three boilers connected to the system during the second week. This means that, with an average of 120 megawatts connected to the scrubber system, we were producing approximately 7,000 tons of sludge in a two week period. Or, stated another way, if the entire plant were connected to the scrubber system, we would fill a pond within a week. The major factor contributing to this change in capacity proved to be an increased fly ash loading of the scrubber system. The sludge disposal system was based on a 90% combined collection efficiency of the mechanical dust collectors and electrostatic precipitators. The transition of the new scrubber ductwork to the old ductwork is such that the gas flow pattern of the gases through the precipitators proved to be greatly disrupted. Velocity traverse data indicated that laminar gas flow no longer exists. Rough estimates indicated that the amount of particulates leaving the precipitators and entering the scrubber system may have trippled. Additional details on the sludge handling will be covered later.

2. ID Fan Stress

As part of the continuing investigation to determine the conditions of the ID fans, Structural Dynamics Research Corporation (SDRC) was engaged to conduct a series of strain gage tests to determine the structural stability of the fans. Their tests indicated that the yield strength was being exceeded in several portions of the fan blades, and that a degree of metal deformation was taking place. After additional strain gage testing, SDRC recommended the installation of doubler (reinforcing) plates on each of the blades to reduce the stresses to acceptable levels. After actual tests with stressed welded specimens in the fan atmosphere, it was also recommended that the doubler plates be welded with an Inconel 112 rod, rather than the Carpenter 20, 4 NIA or 8 NI2 rods previously used. Since the installation is on a fan-by-fan basis, so that a spare scrubber train would always be available for emergency backup, it is expected that all four fans will not be completed until the end of November, 1974.

3. ID Fan Attack

Frequent shut down of the ID fans for inspection revealed that significant attack was still taking place. Despite the addition of lime for SO_2 removal and pH control, a low pH was being encountered in the ID fan drains. This results from additional SO_2 scrubbing occuring with the fan spray system. In a trial installation, caustic was added to the fan spray water. However, an inordinate quantity is required to obtain even a pH of 4, and the trial will soon be ended. As another attempt to alleviate the attack, a new type of fog nozzle was installed on one of the ID fans in an attempt to increase the effectiveness of spraying. No evaluation is yet possible.

4. ID Fan Deposits

In addition to the cleaning being accomplished by both the original and the new fan spray systems, it was necessary to periodically remove the ID fans from service to remove deposits by manual methods. In recent weeks, this phenomenon has not required the need to clean the blades as frequently.

5. Recycle Pumps

An unsatisfactory degree of wear (about 30% in three months) is being experienced on the recycle pumps to the point where pump parts are being diverted from the Elrama scrubber system

to Phillips at such a rapid rate that the stock of installed pumps at Elrama will soon be depleted. Experimental pump impellers and wear rings of three different materials and design will be installed.

6. Thickener Capacity

Modifications were made to the thickener tank overflows to increase their hydraulic capacity and thus compensate for the increased dust loading and provide spare capacity.

7. Throat Dampers

Significant unacceptable accumulations are still being found in and around the scrubber throat damper operating mechanisms. These have restricted the damper operation and resulted in operation at pressure drops of up to 10 inches instead of the normal 6 inch drop. Cleaning requires removal of the train from service for manual removal of the mechanism and hand cleaning. About 288 manhours per scrubber are required.

8. Sump Pumps

The ID fan spray sump pumps have been wearing out much faster than anticipated. This is due in part to the low pH and to the higher solids concentration in the fan drains. Once again, we have had to draw on the Elrama installation for replacements.

9. Closed Loop Operation

A closed-loop system may be possible at maximum load with all boilers cut-in. However, the Phillips Power Station is not a base load station, and as a result, the load fluctuates between 30% and full load. At the lower loads, less water is evaporated from the system, while many of the points of water addition (purge, seal and spray water) continue. This results in an excess of water in the system. Temporary permission was obtained from the Pennsylvania Department of Environmental Resources (PDER) to discharge the excess to our existing bottom-ash settling ponds. This permits the settling out of particulate matter and dilution of the blowdown prior to discharge to the river.

10. SO_2 Guarantee Performance Tests

In July, 1974, several tests were made on the dual stage prototype scrubber for SO_2 removal, with inlet SO_2 concentrations ranging from 1263 ppm vol. to 1,603 ppm. at stoichiometric ratios from 1.01 to 1.15 the SO_2 removal ranged from 86% to 93%. The guaranteed SO_2 removal is 80%.

SLUDGE TREATMENT & DISPOSAL

At the time the present period of operation started, the sludge additive system had been completed to the point where it was considered operable. However, it soon developed that the pumping system for the additive was operating below design capacity. The

necessitated pumping a slurry with higher solids content, and the 750 ft. long transfer lines were frequently out of service due to plugging.

This stabilization additive chosen for use is Calcilox, a proprietary product of the Dravo Corporation. This material was developed in the approximate period of October through December, 1972, when we re-installed the Chemico pilot scrubber for the sole purpose of making sludge. Industry knowledge of sulfate-containing scrubber sludge and means of stabilization appeared almost totally lacking at that time. The scrubber was connected so it could be supplied from either upstream or downstream of the existing dust collectors of the No. 4 boiler to enable experiments with both clean and dirty gas. The material developed, Calcilox, is of the consistency of dry cement and, on the basis of laboratory tests, has the property of consolidating the sludge so that it can be disposed of as land fill without an objectionable leachate. The degree and time of consolidation depends on the amount added (3-15% by dry weight of sludge), the pH of the sludge (10.5 appears suitable for our curing time), and temperature (lower temperatures slow the process). Since actual field leaching tests had not been made, we installed two membrane-lined ponds in an inactive ash disposal area to enable collection and retention of leachate from Calcilox-treated sludge. Bottom drain systems were provided with valves to enable leachate sampling at intervals. One of the ponds has 22,860 yd^3 capacity, the other 5720 yd^3. These capacities may be increased by 50% if the material proves suitable for successive layering and compacting.

During the previously noted difficulties with the additive system, Calcilox was either added sporadically or not added at all. As a result, the sludge after residence time in the ponds was of a "soupy" nature, which made it difficult to excavate with a clam shell and to transport in open trucks. Prior to placing the material in the trucks, fly ash from the ash silo was deposited in the rear of the truck to seal the tailgate. Because of the difficulties in handling the sludge, additional boilers could not be connected to the scrubber system since it would tax our ability to remove the sludge from the ponds as rapidly as it was being produced. Since the sludge did not have the amount of additive which would normally be added prior to discharging it to the ponds, no appreciable degree of stabilization took place in the ponds. We did not feel that the "soupy" material was representative of that which would result from the normal sludge disposal system, and were reluctant to use one of the lined test ponds for this material. Therefore, we requested interim permission from the State's Solid Waste Disposal Division of the PDER to dispose of the material on the ash disposal area where we normally dispose of the fly ash and bottom

from the generating plant. The state consented to our request, and we started disposal of the unstabilized sludge on our ash disposal site. It was spread in thin layers, mixed with additional fly ash and then compacted.

Handling of the sludge was extremely difficult. The trucks could only be loaded to approximately 1/2 capacity because of the danger of the sludge flowing over the sides if the truck stopped or started too abruptly or made turns at excessive speed. In addition, because it was impossible to prevent sludge from dripping onto the sides of the truck during the truck loading operations, it was necessary that the trucks be washed prior to leaving the plant premises. Even with such precautions, occasions arose when sludge was deposited on the roadways. After several warnings from the local police and the Pennsylvania Department of Transportation, it was necessary to rent a street cleaner and a water sprinkler truck to clean the streets during the hours of sludge hauling.

In approximately May, 1974, modifications were completed on the additive system, and Calcilox was then added on a continuous basis to the sludge with around-the-clock technical supervision. Filling time per pond was about 10-14 days with the increased quantity of fly ash, instead of the 28-30 days which had been planned. Similarly, the curing time was reduced from 30-60 days to 14. However, with about 10% Calcilox addition the sludge did consolidate to the extent that drag-line excavation was possible, truck tailgates did not require sealing, and it was possible to fully load the trucks. Observations of the sludge during excavation showed that although the top layer resembled hard clay in consistency, it became earth-like and then almost fluid near the bottom. It was necessary to mix the lower-most layer with dryer material from the upper layers to obtain a satisfactory handling quality.

The consolidated material was trucked to and deposited in one of the lined areas for leachate monitoring. However, the thixotropic nature of the material was such as to prevent either leveling or successive layering of truckloads. It was necessary to tailgate the sludge and then let it stand (cure?) for about six more weeks before it could be leveled, and dozers and trucks did not get "hung-up." This, of course, slows the disposal process considerably.

Our present procedure is to dump consolidated sludge to the lined area whenever possible. At other times, it is mixed and compacted with dry fly ash on the normal disposal area. We have now been monitoring the bottom drains from the lined area at weekly intervals for six weeks. In that time, the total dissolved solids (TDS) have varied from an original

2203 mg/l to the present (October 2) 3380 mg/l. A sample analyzed by the PDER on September 22 verified the results on our own sample of that same date. No record of total volume of leachate has been maintained, and it is realized that this quantity can affect the measured TDS appreciably. Similarly, it is realized that the method of disposal by tailgating and our inability to level the top of the sludge to a possibly impervious surface has also had an effect.

In addition to the above tests, leachate studies were conducted on a more closely controlled basis. About June 1,1974, we used a concrete mixture to prepare four sludge mixtures with various additives. The additives were fly ash, 2% hydrated lime, 5% hydrated lime and 11% Calcilox. Each mix was then added to a plastic wading pool which had previously been fitted with a valved underdrain system for leachate sampling. Since the tests started, we have added water to each pool once each week so as to cover the sludge after first sampling and draining all water from the previous week. After fourteen weeks, the most meaningful tests are those with the 5% lime and the Calcilox. They show that the total dissolved solids (TDS) on the lime test started at 1450 mg/l and are now 460 mg/l. The TDS on the Calcilox started at 3370 and are now 2000. Penetrometer readings in that time have increased to 2.7 tons/ft^2 on the lime and 4.5+ on the Calcilox. In summary, while more salts are leached from the Calcilox mix, the degree of consolidation is higher than that of the lime.

FUTURE OPERATING PLANS

Due to improvements in the method of sludge treatment and handling, and due to close control of the thickener tank underflow operation, it was possible to cut-in a fourth boiler to the scrubber system on August 18, 1974. This increased the capacity connected to the scrubber system to approximately 180 megawatts. Our plan is to operate the scrubber system with the four boilers for a period of time to determine the extent of any aggravation of existing problems and the occurrence of any new problems. If the problems become intolerable, it may be necessary to return the scrubber system to a three boiler operation. However, if the problems are not severe, we anticipate the possibility of adding a 5th boiler to the scrubber system. We are extremely cautious in our optimism because of the number of unknowns in the sludge disposal system such as the following:

1. Since the lime feed system is essentially operating at maximum capacity, additional boilers will reduce the pH in the scrubber system. We are told that a reduced pH would adversely effect the stabilization of the sludge. However, we do not know to what degree it will be affected. Also, if additional boilers are connected to the scrubber system,

the rate of sludge production may not permit optimum stabilization period which now appear to be greatly in excess of 14 days.

2. With the oncoming cold winter months, it is not known to what extent low temperatures will hinder stabilization.

3. If additional boilers are connected to the scrubber system, and it becomes impossible to optimize stabilization of the sludge prior to removing it from the ponds, it may be necessary to again seal the tailgates with fly ash prior to loading the trucks with sludge. This would then be conducive to sludge material dropping on to the road, freezing and causing complaints from the local citizens.

If we can connect five out of the six boilers to the scrubber system by November 30, 1974, we will begin our ten-month test program at that time to evaluate the efficiency, reliability, and practicability of the scrubber system. A decision would then be made on September 30, 1975, concerning the installation of additional SO_2 removal equipment for compliance with the SO_2 emission limitations. The number of additional second stage scrubbers required for compliance with the regulations will be determined during the ten-month test program, and this will establish the completion date for installation of all additional scrubbers.

In the hope of obtaining higher efficiencies of SO_2 removal with the use of lime, Duquesne Light is conducting tests using Thiosorbic lime (a Dravo development) which is a lime having a concentration of magnesium oxide in the order of 4 to 6%. Various tests on pilot scrubber systems indicate that the higher reactivity of such a lime results in SO_2 single-stage removal efficiencies in the 90's. In preparation for these tests, one of the single stage scrubbers was isolated along with one of the thickener tanks. This isolation was necessary to establish and maintain the desired chemistry, since lime slaking capacity is insufficient to maintain the necessary conditions in all scrubbers and both thickeners. A test run with Thiosorbic lime was made in September, 1974. However, we encountered difficulties in achieving a sufficiently high rate of utilization of the magnesium oxide. A few cursory tests under these conditions indicated SO_2 removal efficiencies somewhat better than those with high calcium lime, but also significantly less than anticipated. The tests were suspended later in September to further evaluate means of increasing the reactivity and utilization of the Thiosorbic lime. Resumption is planned for about October 21.

As of August, 1974, construction on the Elrama scrubber system, which is essentially identical to the Phillips scrubber system, had progressed to a point where no additional meaningful work could be accomplished until the problems with the Phillips scrubbers are resolved. With the modifications and test programs now being conducted at Phillips, it is anticipated that solutions to the present problems may progress to the point where startup of the Elrama scrubber system may be possible in May, 1975.

AVAILABILITY AND RELIABILITY

The availability of the Phillips scrubber system is meaningless at this point since we have essentially 100% backup. In other words, there are two spare scrubber trains which can be placed in service whenever a problem arises on an operating train. The service hours for each train for the period from March 17, 1974 through September 30, 1974 are 3430 hours for No. 1 train (dual stage), 1678 hours for No. 2 train, 1931 hours for No. 3 train, and 2803 hours for No. 4 train.

Reliability was built into the design of the system which called for a spare scrubber train enabling us to carry almost full station load on three scrubber trains. In addition, a degree of reliability is built into each scrubber train through the installation of spare pumps, thickener capacity and backup electrical controls.

We do not view bypassing as the solution to maintaining acceptable reliability. However, we have incorporated a manual type bypass into our scrubbing system as the best approach to avoid the serious consequences of scrubber failure. The system uses blanking plates to redirect the gas flow to the original stacks, and the boilers have to be shut down during the plate change. Under normal circumstances, this process would consume several days depending on the availability of manpower. There really was no alternative in designing a bypass system for our plants. Mechanical bypass systems utilizing a damper arrangement require tight dampers, and sufficiently tight dampers have yet to be developed. We also had serious space limitations on installation of a mechanical damper system.

CAPITAL AND OPERATING EXPENSES

As of this date, the scrubber systems at Phillips and Elrama represent a capital investment of approximately $61 million. It is expected that an additional $19 million will be required for equipment necessary to comply with the SO_2 emission limitations. This will represent a total investment of $80 million or approximately $91 per kilowatt, exclusive of the cost of any additional sludge disposal facilities required.

A recent estimate indicates that the annual operating and maintenance expenses, including fixed charges, at Phillips and Elrama for the SO_2 scrubbing will be in excess of $30 million per year, or 3 mills per kilowatt hour, exclusive of additional sludge disposal facilities which will be required for full SO_2 removal operation. These expenses would represent an increase of approximately $11 per ton of coal consumed. Expressed in different terms, these expenses, without fixed charges, would represent approximately a 50% increase over the total operating and maintenance expenses for 1973.

In an effort to estimate the total capital and operating costs that would ultimately be incurred for the scrubber systems at the Phillips and Elrama Stations, including provision of adequate sludge disposal facilities for full SO_2 removal, a preliminary evaluation was made of the additional property required for development into a disposal area and the additional expenses involved in disposing of the sludge. This estimate indicates possible capital expenditures of $110 million for scrubber installation and property acquisition and development, of which $61 million has thus far been spent. This represents an investment of approximately $124 per kw.

Present estimates of the sludge disposal costs are $7 to $10 per wet ton, or $15 to $20 per dry ton of sludge.

Future Objectives

Although we feel we may be able to overcome the present operating and equipment problems with additional time, effort and expense, there are five levels of performance which must be satisfactorily resolved if this flue gas desulfurization system is to be operationally feasible and economically acceptable.

1. Reliability - meaning the scrubber facility should meet the degree of availability, normally expected of power generating equipment.

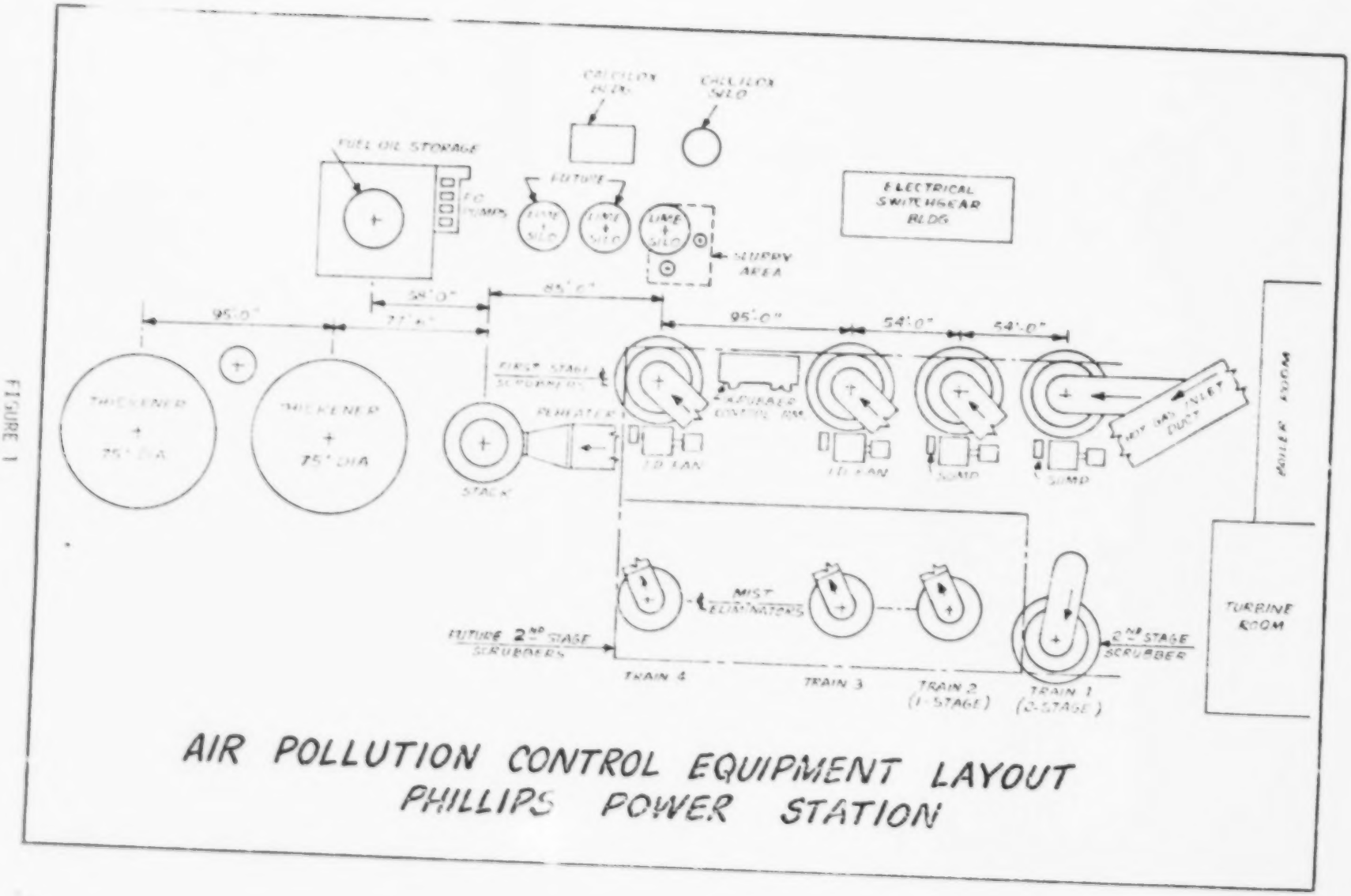
2. Turndown - the capability of the flue gas desulfurization equipment to follow the normal cycling operation of a power generation facility without serious disruption to both the scrubber system and the generating plant.

3. Closed Loop Operation - the ability to operate without the discharge of objectionable liquid effluents as dictated by the applicable water quality requirements.

4. Sludge - the technique for disposal of sludge from the flue gas desulfurization system without any adverse ecological effects.

5. Cost consideration - capital and operating expenses should not be of such a magnitude as to impose unreasonable financial burden on the operator/ owner and the consumer.

Until all these areas of concern are resolved, our system cannot be considered a successful operation as reports by others have indicated.



AIR POLLUTION CONTROL EQUIPMENT LAYOUT
PHILLIPS POWER STATION

FIGURE 1
C-25

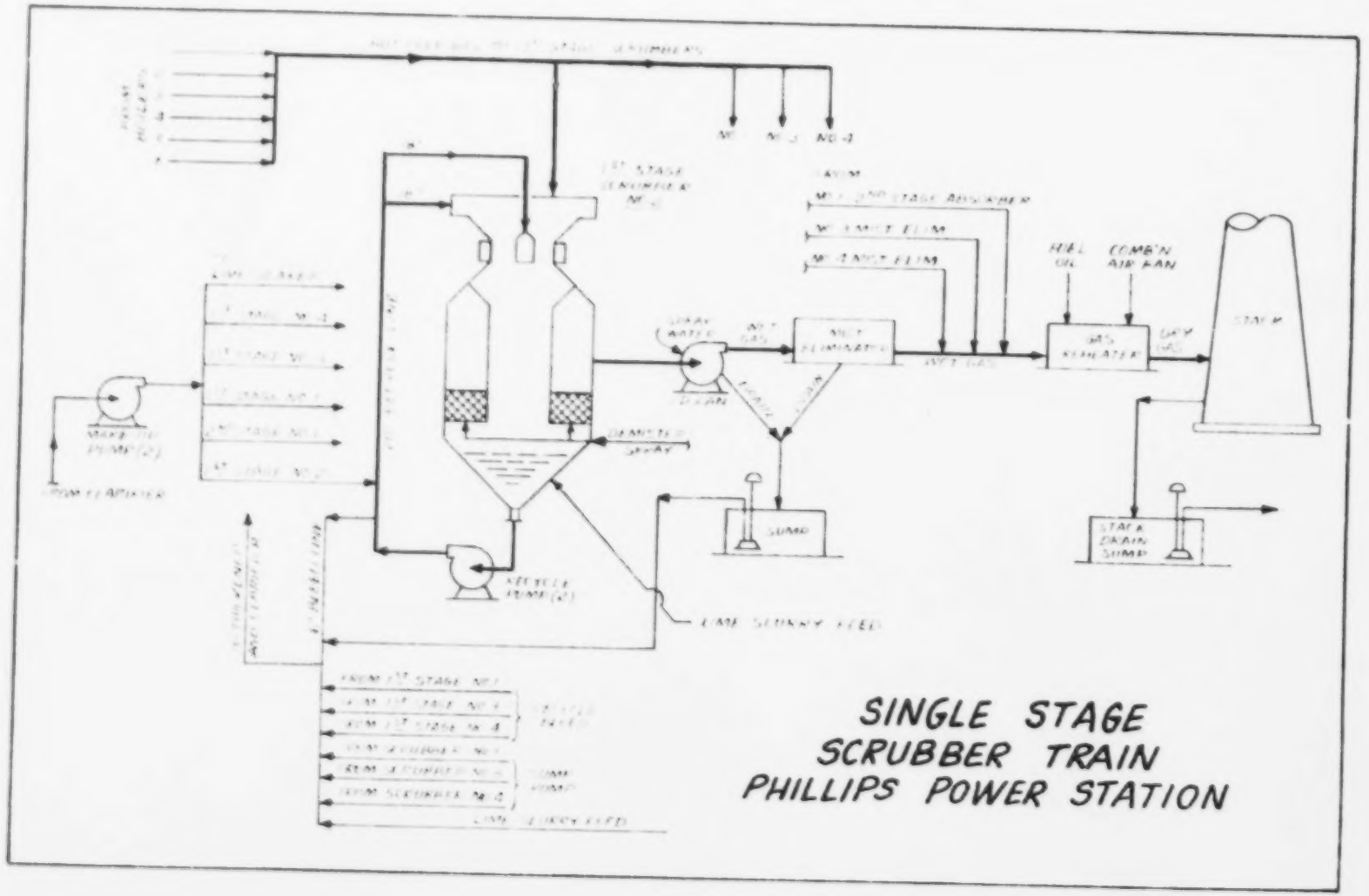


FIGURE 2
C-26

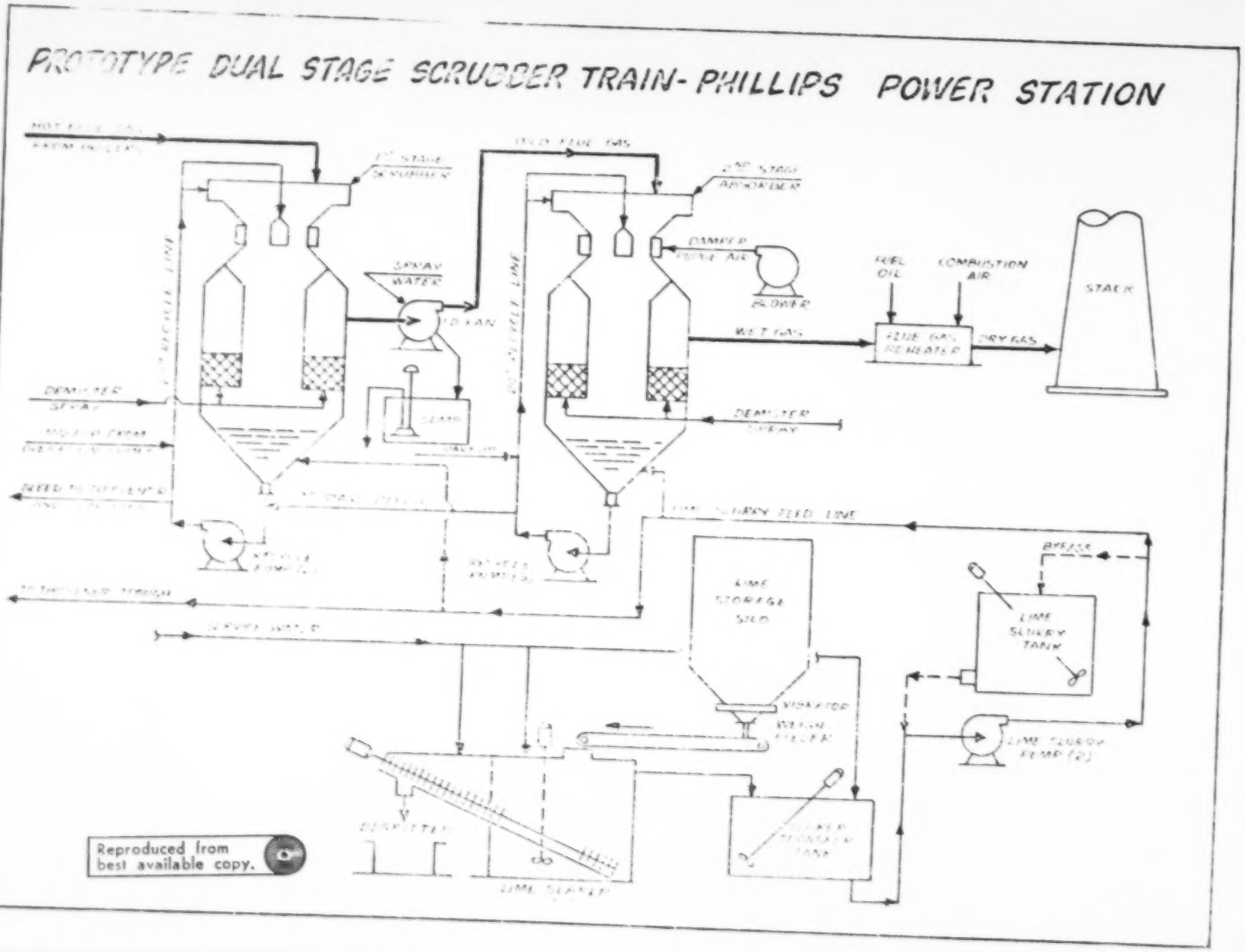

PROTOTYPE DUAL STAGE SCRUBBER TRAIN- PHILLIPS POWER STATION
SPRAY WATER
FUEL OIL
COMBUSTION AIR
STACK
DAMPER
BLOWER
WET GAS
DRY GAS
DEMISTER SPRAY
LIME STORAGE SILO
LIME SLURRY TANK
BYPASS
VIBRATOR
LIME SLURRY FEED LINE
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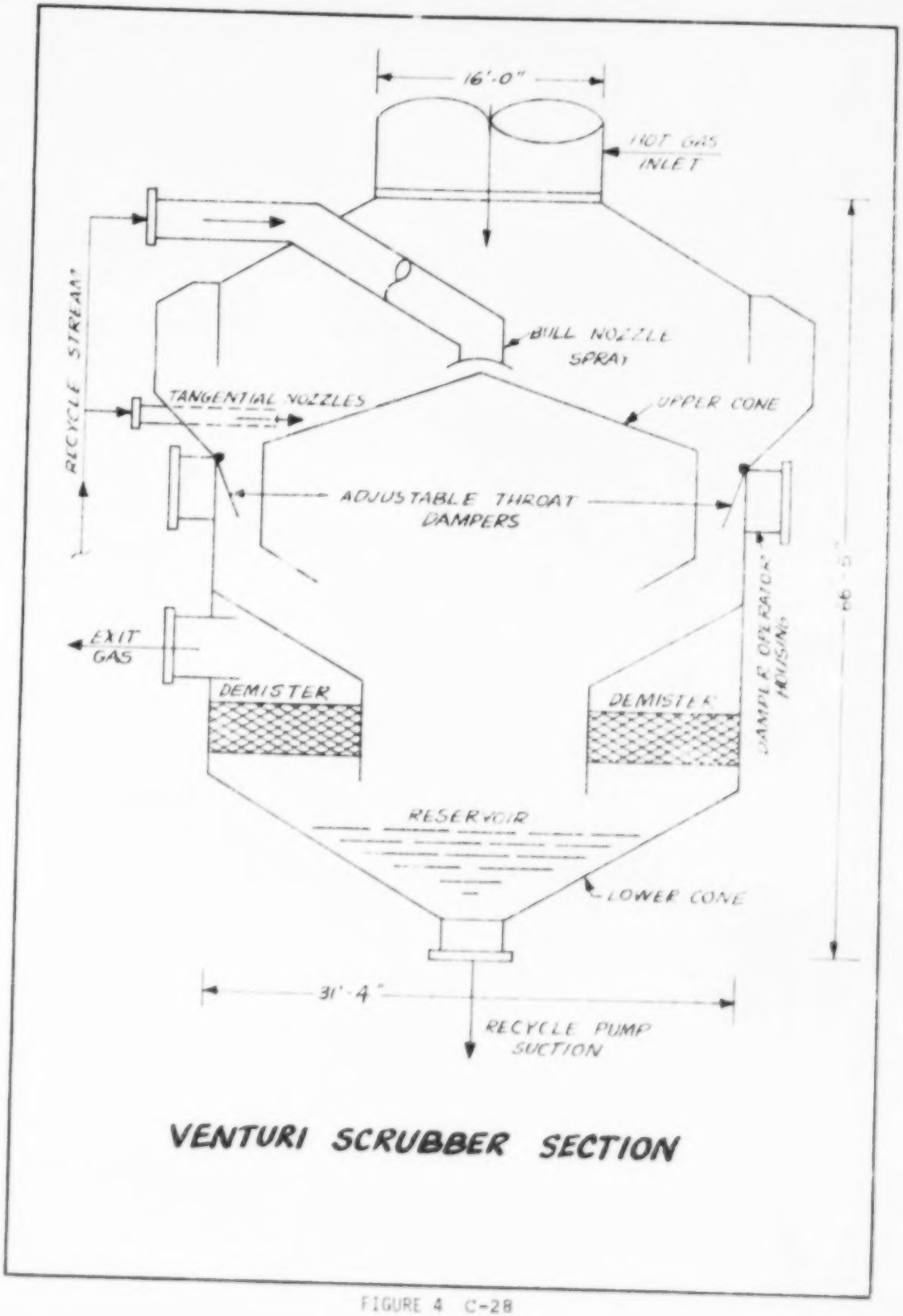
FIGURE 3
C-27



VENTURI SCRUBBER SECTION

FIGURE 4 C-28

SIGNIFICANT DATES

December, 1968	-	Gibbs & Hill, Inc. requested to study methods of compliance.
September, 1970	-	Gibbs & Hill study recommends scrubber and Duquesne Light Company gave authority to Gibbs & Hill to proceed with projects at Elrama and Phillips Power Station.
October, 1970	-	Invitations were extended to bid on scrubber pilot plant.
February-May, 1971	-	Chemico pilot scrubber tests at Phillips underway.
May, 1971	-	Design of full scale system started.
July, 1971	-	Contract for scrubber process including scrubber recycle pumps, reheater and associated controls and instrumentation awarded to Chemico.
December, 1971	-	Construction started at both Phillips and Elrama plant sites.
July, 1972	-	Construction of Phase I at Phillips essentially complete. Phase I consists of one dual stage SO_2 scrubber train and 3 single stage particulate scrubber train with associated lime and thickener equipment.
July 4, 1973	-	Operation began at Phillips with two and eventually three of station's six boilers.
October 8, 1973	-	Scrubber system shutdown for extensive repair.
March 17, 1974	-	Scrubber system began with three of six boilers.
August 22, 1974	-	Fourth boiler put into scrubber system.
October, 1974	-	Fifth boiler put into scrubber system.

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Figure 5